PNG LNG EIS

Landscape and Visual Impact Assessment

FINAL 27th NOVEMBER 2008

PREPARED FOR COFFEY NATURAL SYSTEMS

AND EXXONMOBIL CORPORATION

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1. Introduction

This report assesses the visual impact of the proposed PNG LNG facility on the setting of Portion 152.

1.1 Introduction

The Papua New Guinea Liquefied Natural Gas Project (PNG LNG Project) is an LNG concept that aims to commercialise the gas reserves in the Hides, Angore, Juha, Kutubu, Agogo, Gobe and Moran fields in the Western and Southern Highlands provinces of PNG. The project involves the production of gas and its transportation to an LNG facility at Portion 152 within Central Province, on the coast of the Gulf of Papua. (Refer to Figure 1.1). The gas is to be liquefied at the facility and the LNG product transported to international gas markets.

Esso Highlands Limited (Esso), a PNG subsidiary of Exxon Mobil Corporation (ExxonMobil), is the operator of the PNG LNG Project.

EDAW has been commissioned by Coffey Natural Systems, on behalf of ExxonMobil to undertake a landscape and visual impact assessment of the LNG facilities of the proposed PNG LNG Project as part of an Environmental Impact Statement (EIS).

1.2 Project Overview

The Papua New Guinea Liquefied Natural Gas (PNG LNG) Project involves the development of a number of gas fields and facilities in a series of development phases to produce liquefied natural gas (LNG) for export. The development will also produce condensate. The development of the Hides, Angore, and Juha gas fields and blowdown of the gas caps at the existing Kutubu, Agogo and Gobe oil fields will supply the gas resources. An extensive onshore and offshore pipeline network will enable transportation of the gas to a new LNG Plant near Port Moresby and stabilised condensate to the existing oil processing and storage, and offloading facilities at the Kutubu Central Processing Facility and Kumul Marine Terminal respectively. Small amounts of condensate are also produced at the LNG Facilities site.

Esso Highlands Limited (Esso), a Papua New Guinea subsidiary of the Exxon Mobil Corporation (ExxonMobil), is the operator of the PNG LNG Project. The PNG LNG Project will be developed in five phases over a period of 10 years to ensure reliability and consistent quality of supply of LNG for over the 30 year life of the project.

A list of the proposed developments is provided below, and Figure 1.2 shows a schematic of facilities and pipelines:

1.2.1 Upstream Development Components:

Hides gas field development:

- Seven wellpads with a total of eight new wells and re-completion of two existing wells.

- Hides gathering system including gas flowlines from new and re-completed Hides wells.
- Hides spineline and mono-ethylene glycol (MEG) Pipeline in the same right of way (ROW).
- Hides Gas Conditioning Plant.
- Hides–Kutubu Condensate Pipeline in the same ROW as the LNG Project Gas Pipeline.

Juha gas field development:

- Three new wellpads with four new wells.
- Juha gathering system including gas flowlines from new Juha wells.
- Juha spinelines and MEG Pipeline in the same ROWs.
- Juha Production Facility.
- Juha–Hides pipelines right of way (ROW) containing three pipelines including Juha–Hides Rich Gas Pipeline, Juha–Hides Liquids Pipeline and Hides–Juha MEG Pipeline.

Angore gas field development:

- Two new wellpads with two new wells.
- Angore gathering system including gas flowlines from new Angore wells.
- Angore spineline and Angore MEG Pipeline to Hides Gas Conditioning Plant, both in the same ROW.

Gas from existing fields:

- Gas treatment at the Agogo Production Facility and a new Agogo Gas Pipeline from the Agogo Production Facility to LNG Project Gas Pipeline.
- Gas treatment at the Gobe Production Facility and a new Gobe Gas Pipeline from the Gobe Production Facility to LNG Project Gas Pipeline.
- Gas treatment at the Kutubu Central Processing Facility and a new Kutubu Gas Pipeline from the Kutubu Central Processing Facility to the LNG Project Gas Pipeline.
- South East Hedinia gas field development: one new wellpad and two new wells; new gathering system including gas flow lines from the South East Hedinia new wells to the Kutubu Central Processing Facility in the same ROW as the Kutubu Gas Pipeline.

Kopi scraper station.

LNG Project Gas Pipeline:

- Onshore: from Hides Gas Conditioning Plant to Omati River Landfall.
- Offshore: Omati River Landfall to Caution Bay Landfall.

1.2.2 LNG Facilities Development Components:

- Onshore LNG Plant including gas processing and liquefaction trains, storage tanks, flare system and utilities.
- Marine facilities including jetty, LNG and condensate export berths, materials offloading facility and tug moorage.

1.2.3 Supporting Facilities and Infrastructure:

In addition to the principal gas production, processing and transport, and LNG production and export facilities, the project will involve the following permanent infrastructure and facilities:

- New roads and upgrade of existing roads.
- New bridges and upgrade of existing bridges.
- Upgrade of two existing airfields (upstream at Komo and Tari).
- New helipads (multiple).

- New wharf and an upgrade of the existing Kopi roll-on, roll-off facility.
- Water supply systems and pipelines, wastewater and waste management facilities.
- Operations Camps (at Hides, Juha and Tari).

A series of temporary works and access roads will also be required during the construction phase, including:

- Construction camps (multiple).
- Material/pipe laydown areas.

This study focuses on the LNG Facility only.

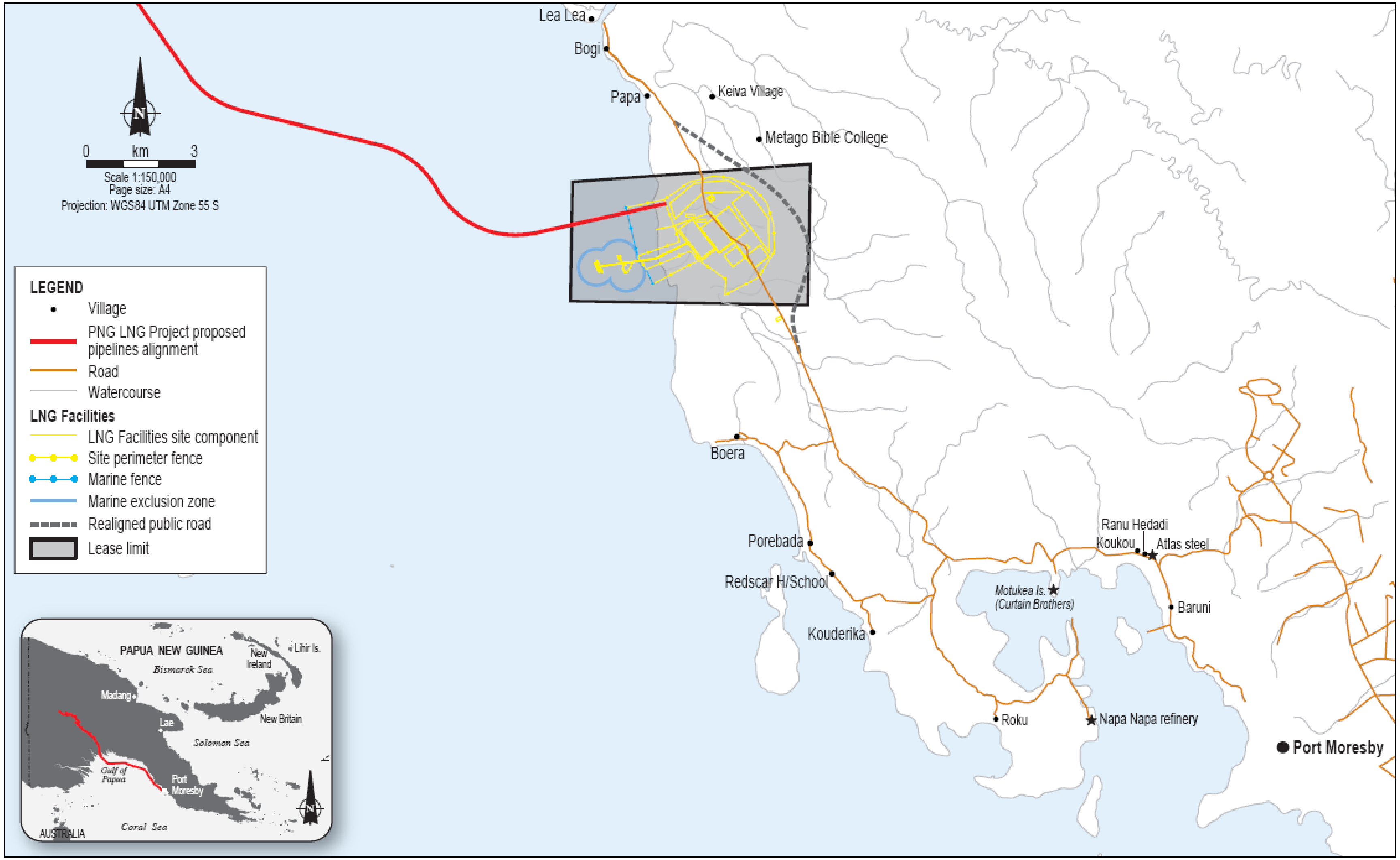


Figure 1.1: Study area context (Source: Coffey Natural Systems)

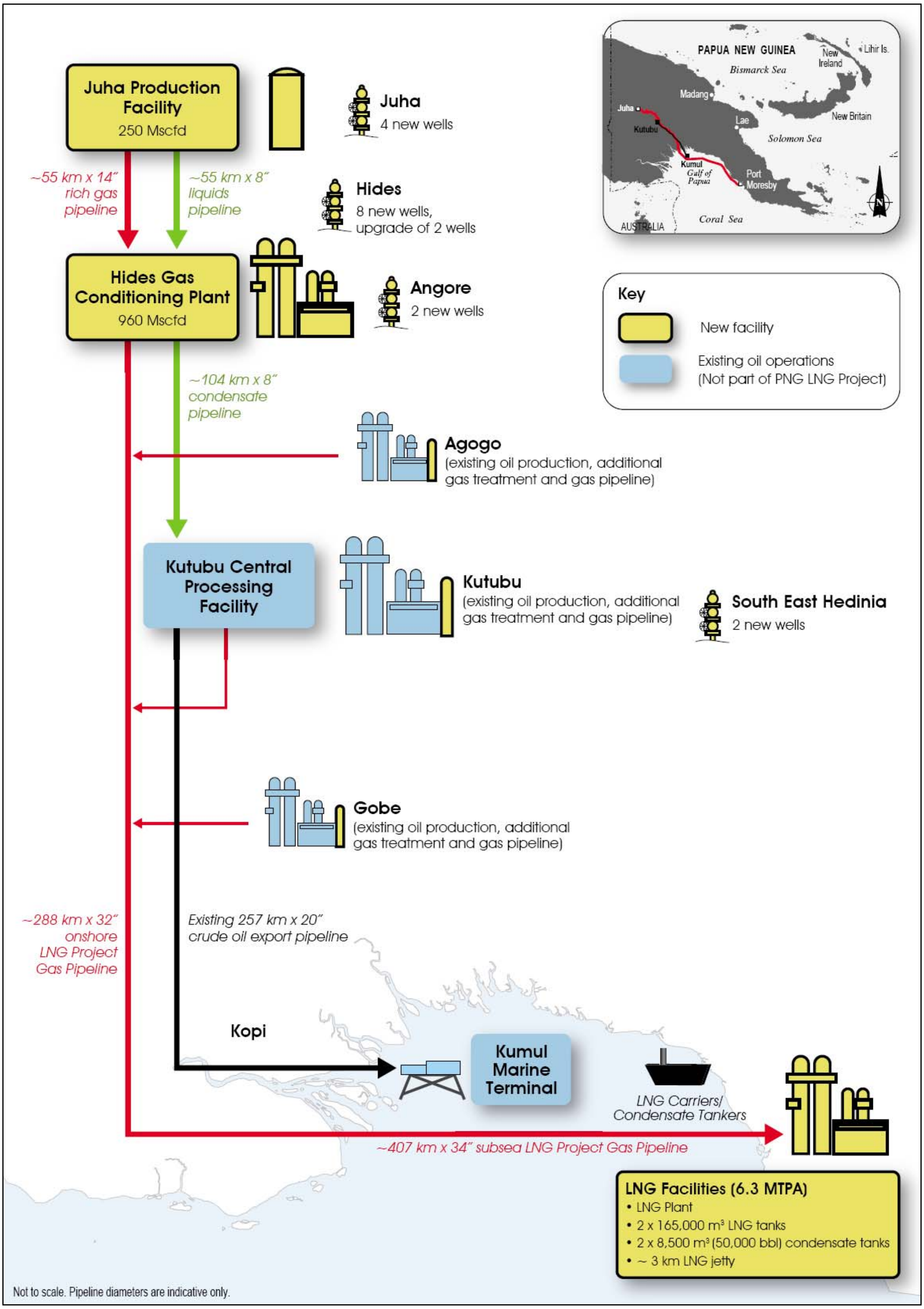


Figure 1.2: Project Overview – New and existing (Source: Coffey Natural Systems)

1.3 Objectives of the Study

The objectives of this visual impact assessment study, as outlined in the PNG LNG Project Visual Impact Assessment Brief, are to:

- Describe the existing landscape character and visual amenity of the study area, identifying sensitive receptors within the study area and key attributes of the landscape and amenity of affected areas.
- Identify potential impacts on visual amenity associated with project construction and operation.
- Propose design responses and measures for the reduction, mitigation and management of potential landscape and visual impacts associated with project construction and operation.
- Assess residual impacts on landscape character and visual values associated with project construction and operation.

1.4 The Study Process

The agreed study process involves the following tasks:

- A review of relevant policy, legislation, standards and guidelines regarding visual and landscape values and develop appropriate standards based on this review.
- A desktop review and site inspection to identify local scenic values, and photograph relevant viewpoints including major and local roads and residences.
- An assessment of the landscape's ability to absorb visual changes associated with the various stages of construction and operation of the project from all relevant viewpoints supported by visual simulations of the site pre-construction, during and post-construction and operation.
- Propose appropriate mitigation measures to ameliorate significant visual impacts.
- An assessment of the residual impacts of construction and operation of the project on landscape character and visual amenity for all relevant viewpoints.

1.5 Study Method

The method employed by EDAW has been undertaken in accordance with the consultants brief and requirements of the assessment process. The approach has been based on an analysis of the setting and assessment of the anticipated impacts of the development of the project. The methodology is comprised of a number of components. These are:

- ***Quantitative Assessment (Refer to Appendix A)***
  - How much of the proposed development is visible from particular viewpoints?

- ***Qualitative Assessment***
  - Visual modification – How does the proposed development contrast with the landscape character of the surrounding setting?
  - What is the quality of the landscape setting?
  - Sensitivity – How sensitive will viewers be to the proposed development?
  - How will the presence of lighting impact on the night time setting?

1.5.1 Approach to Quantitative Assessment

VISIBILITY – RELATIONSHIP WITH VIEWSHEDS

The report defines a number of viewsheds based on distance from the development for the purposes of assessment. The methodology is based on the reduction of impact with an increase in distance between a given viewpoint and the development. (Refer to Appendix A).

Degrees of Field of View Occupied	Potential Visual Prominence – Horizontal Field of View
Less than 5°	***Insignificant*** The development may not be highly visible in the view, unless it contrasts strongly with the background.
5° – 30°	***Potentially Noticeable*** The development may be noticeable. The degree that it intrudes on the view will be dependant on how well it integrates with the landscape setting.
Greater than 30°	***Potentially Dominant*** The development will be highly noticeable.

Table 1.1: Horizontal line of sight - Visual impact / visual prominence

Degrees of Field of View Occupied	Potential Visual Prominence – Vertical Field of View
Less than 0.5°	***Insignificant*** A small thin, horizontal line in the landscape.
0.5° – 2.5°	***Potentially Noticeable*** The development may be noticeable. The degree that it intrudes on the view will be dependant on how well it integrates with the landscape setting.
Greater than 2.5°	***Potentially Dominant*** The development will be highly noticeable, although the degree of visual intrusion will depend on the landscape setting and the width / thickness of the object.

Table 1.2 - Vertical line of sight - Visual impact / visual prominence

1.5.2 Approach to Qualitative Assessment

The method employed by EDAW is based on the Visual Management System (VMS) developed by the US Forestry Service whereby the visual impact of a proposed development is determined by evaluating the degree of visual modification / fit of the development in the context of the visual sensitivity of surrounding land use areas from which a proposed development may be visible. The visual impact resulting from the combination of visual modification and visual sensitivity, or viewer sensitivity, is illustrated in **Table 1.3.**

Viewer Sensitivity

Visual Modification	H	M	L
H	H	H	M
M	H	M	L
L	M	L	L
VL	L	VL	VL

VL = Very Low
L = Low
M = Moderate
H = High

Level of Visual Impact

Table 1.3: Visual impact matrix

VISUAL MODIFICATION

The visual modification level of a proposed development can be best measured as an expression of the visual interaction, or the level of visual contrast between the development and the existing visual environment.

A high degree of visual modification will result if the major components of the development contrast strongly with the existing landscape.

A low or very low degree of visual modification occurs if there is little or minimal visual contrast and a high level of integration of form, line, shape, pattern, colour or texture values between the development and the environment in which it sits. In this situation the development may be noticeable, but does not markedly contrast with the existing modified landscape.

Throughout the visual catchment (or Zone of Visual Influence) the degree of modification will generally decrease as the distance from the development site to various viewing locations increases.

VISUAL SENSITIVITY

Visual sensitivity is a measure of how critically a change to the existing landscape will be viewed from various use areas. Different activities undertaken within the landscape setting have different sensitivity levels. For example, visitors or people with no benefit from the project will generally view changes to the landscape more critically than agricultural or industrial agricultural or industrial workers in the same setting. Similarly, individuals will view changes to the visual setting of their residence more critically than changes to the visual setting of the broader setting in which they travel or work.

The visual sensitivity of the development depends on a range of viewer characteristics. The primary characteristics used in this study are:

- Land use.
- Distance of the development from viewers.
- Its visibility from critical viewing areas.
- View angle.

The visual sensitivity of land uses was assessed to assist in determining the visual impact of the development. As distance from the viewer to the proposed development increases, the level of sensitivity reduces. Visual catchments are defined for a range of distances that relate to sensitivity. These are:

- Regional – in excess of 5km distant
- Sub-regional – between 1km and 5km distant
- Local – within 1km.

1.5.3 Cultural Values and Sensitivity

Typical levels of viewer sensitivity to the development specifically developed for the study area and its population based on the Visual Management System (VMS)[1] are outlined in Table 1.4.

[1] Forest Service USDA, *National Forest Landscape Management, Volume 2, Chapter 1, The Visual Management System. Agricultural Handbook No. 462, April 1974.*

Visual Use Area	Foreground Local Setting 0 - 0.5	 0.5 - 1km	Middleground Sub Regional Setting 1 - 2 .5	 2.5 - 5 kms	Background Regional Setting > 5 kms
Culturally Significant Areas	H	H	H	M	L
Major Town (Port Moresby)	H	H	H	M	L - VL
Villages	H	H	H	M	L
Schools – Metago Bible College	H	H	M	M	L
Offshore Fishing Grounds	M	M	M	L	L
Offshore Transport Routes	M	M	M	L	L
Coastal Gathering Areas	M	M	L	L	VL
Farming Land	M	M	L	L	VL
Local Roads	L	L	L	VL	VL

Legend - H = High, M = Moderate, L = Low, VL = Very Low

Table 1.4 – Typical visual (viewer) sensitivity.

1.5.4 Assessment of Impacts of Night Lighting

The assessment of the impacts of lighting at night time has been based on – Guidance Notes for the Reduction of Obtrusive Light, published by The Institution of Lighting Engineers, UK, 2005. (Refer to Appendix B).

The guidelines include a range of categories with which to describe the lit situation of the landscape. These environmental zones are supported by design guidance for the reduction of light pollution which can then inform proposed mitigation techniques.

1.6 Policy Considerations

1.6.1 International Finance Corporation (IFC) – World Bank Group - Environmental, Health and Safety Guidelines for Onshore Oil and Gas Development

The World Bank publishes guidelines for projects that are undertaken with its funds. Key guidelines of relevance to landscape and visual issues are:

“The visual Impact of permanent facilities should be considered in design so that impacts on the existing landscape are minimised. The design should take advantage of existing topography and vegetation, and should use low profile facilities and storage tanks if technically feasible and if the overall facility footprint is not significantly increased. In addition consider suitable paint colour for large structures that can blend with the background.”

Additional Considerations included:

- *"Minimise areas to be cleared.*
- *Minimise the width of a pipeline right-of-way or access road during construction and operations as far as possible."*

Refer to Appendix C - International Finance Corporation (IFC) – World Bank Group Environmental, Health and Safety Guidelines for Onshore Oil and gas Development.

2

2. The Existing Landscape

The study area is located on Caution Bay, 20 km northwest of Port Moresby.

This assessment of the landscape and visual impacts has been undertaken for the following settings:

- ***Regional*** - More than 5km from the project area.
- ***Sub–Regional*** – Between 1km and 5km from the project area.
  - *Distant Sub–Regional* – Between 2.5km and 5km from the project area.
  - *Near Sub–Regional* – Between 1km and 2.5km from the project area.
- ***Local*** – Within 1 km of the project area.

2.1 Site Context and Summary

The study area is located on the coastline of the Gulf of Papua on Caution Bay, approximately 21kms northwest of Port Moresby.

The landscape type of the broader coastal plain of the Gulf region is typified by plateaus between 100 and 400m high, dissecting valleys and flood plains, vegetated with monsoonal riverine communities. (Refer to Figures 1.1, 2.1 and 2.2 for regional locations and features).

2.2 Land Use

2.2.1 Regional Setting

Within the regional setting, Port Moresby, the nation's capital, is located 21km to the southeast of the site. It is comprised of a commercial centre and major port complex located close to the coastline, with support industry and residential areas extending inland and along the coastline for approximately 10kms.

The villages of Kido and Lea Lea are located within the regional setting on the coastline to the northwest of the site, and Kouderika and Porebada to the southeast.

Primary landuses in the regional setting are agricultural, comprised of grazing and cropping / cultivation. Existing forests are used as a resource for construction materials and firewood.

Offshore, the coastal zone is used as a transport route between coastal villages as well as for fishing. The intertidal zone is used for the gathering of food and materials.

2.2.2 Sub–Regional Setting

The villages of Papa Papa, Papa No. 2 and Boera are located within the sub-regional setting. All except Papa No. 2 are located on the coast.

A large proportion of the sub-regional setting is cleared and used for agricultural activities.

As for the regional setting, the coastal zone within the sub-regional setting is used for inter-village transport as well as fishing and intertidal zone gathering.

2.2.3 Local Setting

There are no villages within the local setting. The land within the local setting was previously used for cattle grazing and is currently unused. As for the other settings, the coastal zone is used for fishing and intertidal zone gathering.

2.3 Topography / Hydrology

2.3.1 Regional Setting

The site is located on the coastal plain at Caution Bay, which is approximately 14 kms wide, formed by Redscar Head to the northwest and Boera Head to the southeast. (Refer to Figure 2.1 and 2.2.)

The coastal plain varies in width from 3 to 5km throughout the regional setting, extending from the Kido River estuary in the northwest to Uda Bada Hill inland of Boera Head. Further inland the coastal plain transitions to a series of northwest to southeast aligned low hills, including Kokoru Hill, 185m, Iokoru Hill, 298m, Round Tree Hill, 321m and Huhanama Hill, 405m above sea level (ASL).

The areas of elevated topography are generally separated by broad valleys, with water courses, many of which are ephemeral, flowing after the wet season but not throughout the dryer times of the year. The lower reaches of the more significant streams are tidal.

2.3.2 Sub–Regional Setting

Within the subregional setting, Round Tree Hill is the most elevated location, with most of area being less than 50m ASL.

2.3.3 Local Setting

Within the local setting, the topography is generally less than 40m ASL The catchment of the Vaihua River, a small mangrove lined tidal inlet, is contained with the LNG facilities site.

The coastal zone within the local setting includes the coastal salt pan and the near shore shallows.

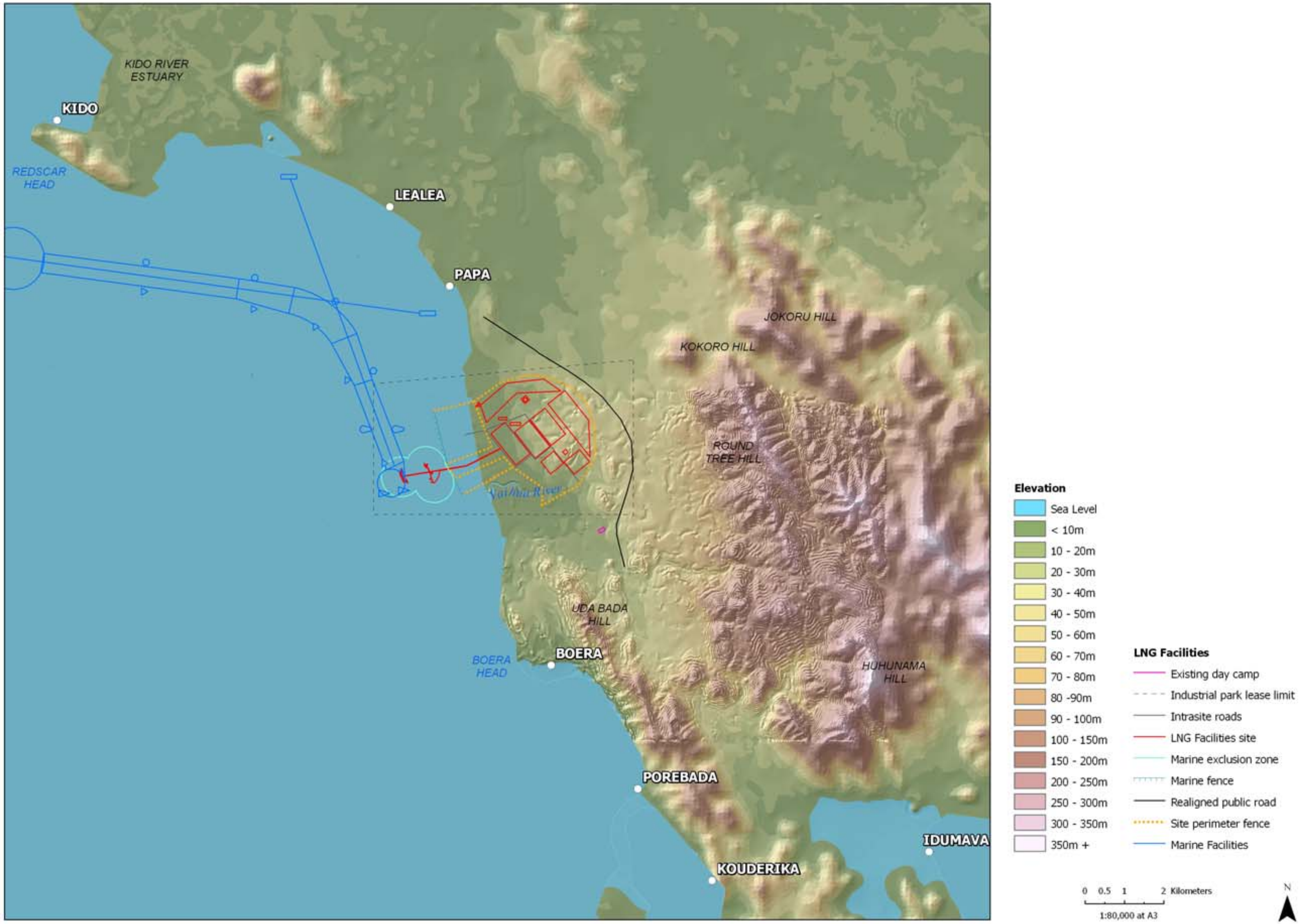


Figure 2.1: Elevation

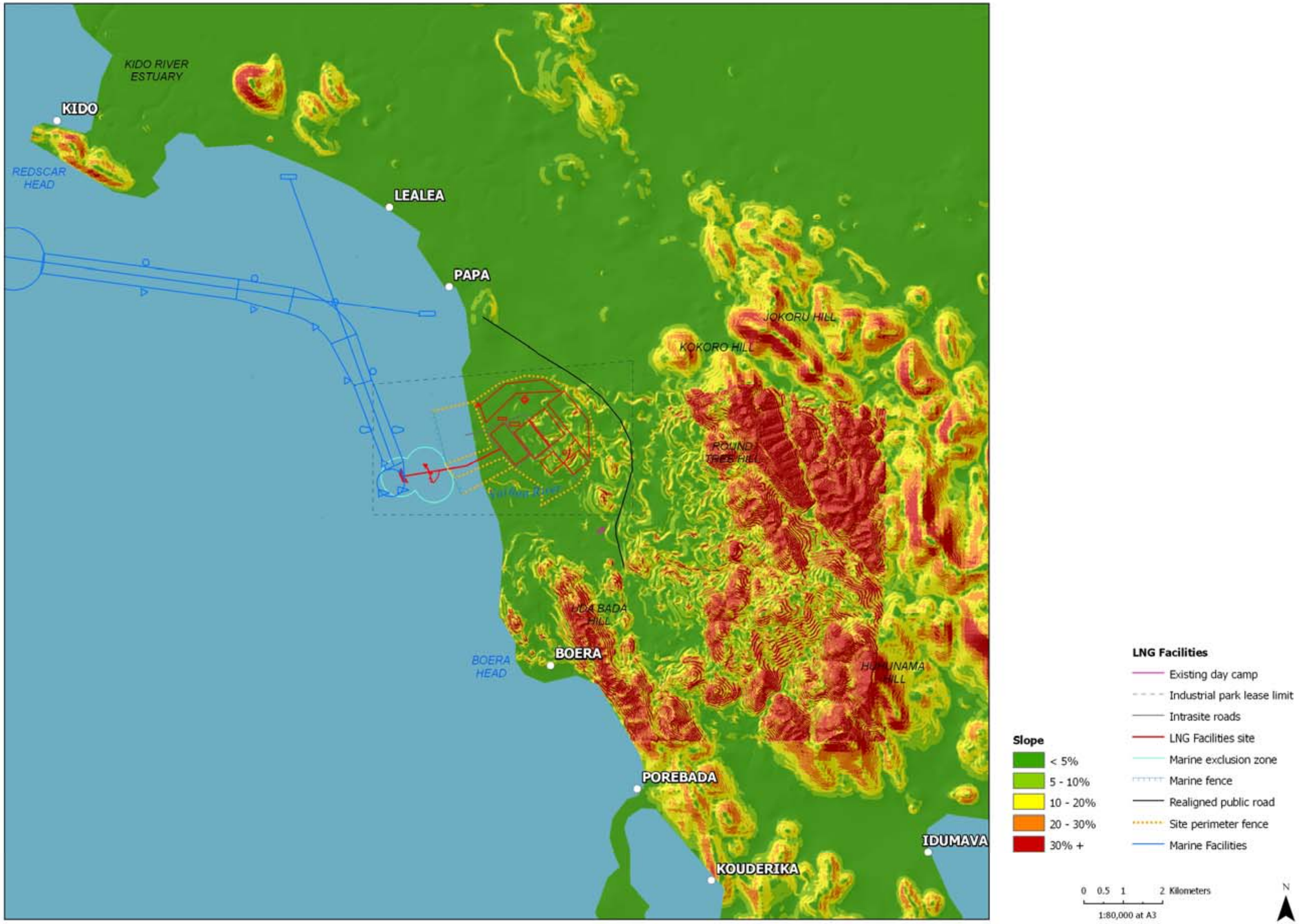


Figure 2.2: Slope

2.4 Vegetation and Landscape Character

2.4.1 Regional Setting

The relatively low level of rainfall by comparison with the majority of PNG, less than 1,000mm per annum which falls mainly in the warmer months, in conjunction with the low fertility soils, results in a relatively open vegetation cover that is classified as Savannah. The main site area is generally cleared of substantial vegetation and the vegetation cover is comprised mainly of grasses and lower herbaceous shrubs. (Refer to Figures 2.3 and 2.4)

Taller and denser vegetation is primarily confined to steeper slopes, more elevated areas and watercourses or drainage lines. The coastal zone is fringed by dense stands of mangroves.

2.4.2 Sub–Regional Setting

Within the regional setting, scattered trees, predominantly eucalypts, are present on higher hills and along waterways / drainage lines and dense bands of mangroves line the coastline. The dominant vegetation type throughout the setting is tall grassland.

The landscape is flat to slightly undulating and views are open and expansive. The higher hills to the north east provide a backdrop to the coastal plain.

2.4.3 Local Setting

The local setting is generally cleared of trees with tall grasses being the dominant vegetation over the site. Mangroves along the intertidal zone are the dominant taller vegetation community. Other stands of taller and denser vegetation are present along the drainage lines of the local setting.

The local setting is generally flat to slightly undulating. Views are generally open and expansive. However the coastal mangroves confine the extent of views from non-elevated locations.

Figure 2.3: Aerial photograph depicting vegetation cover

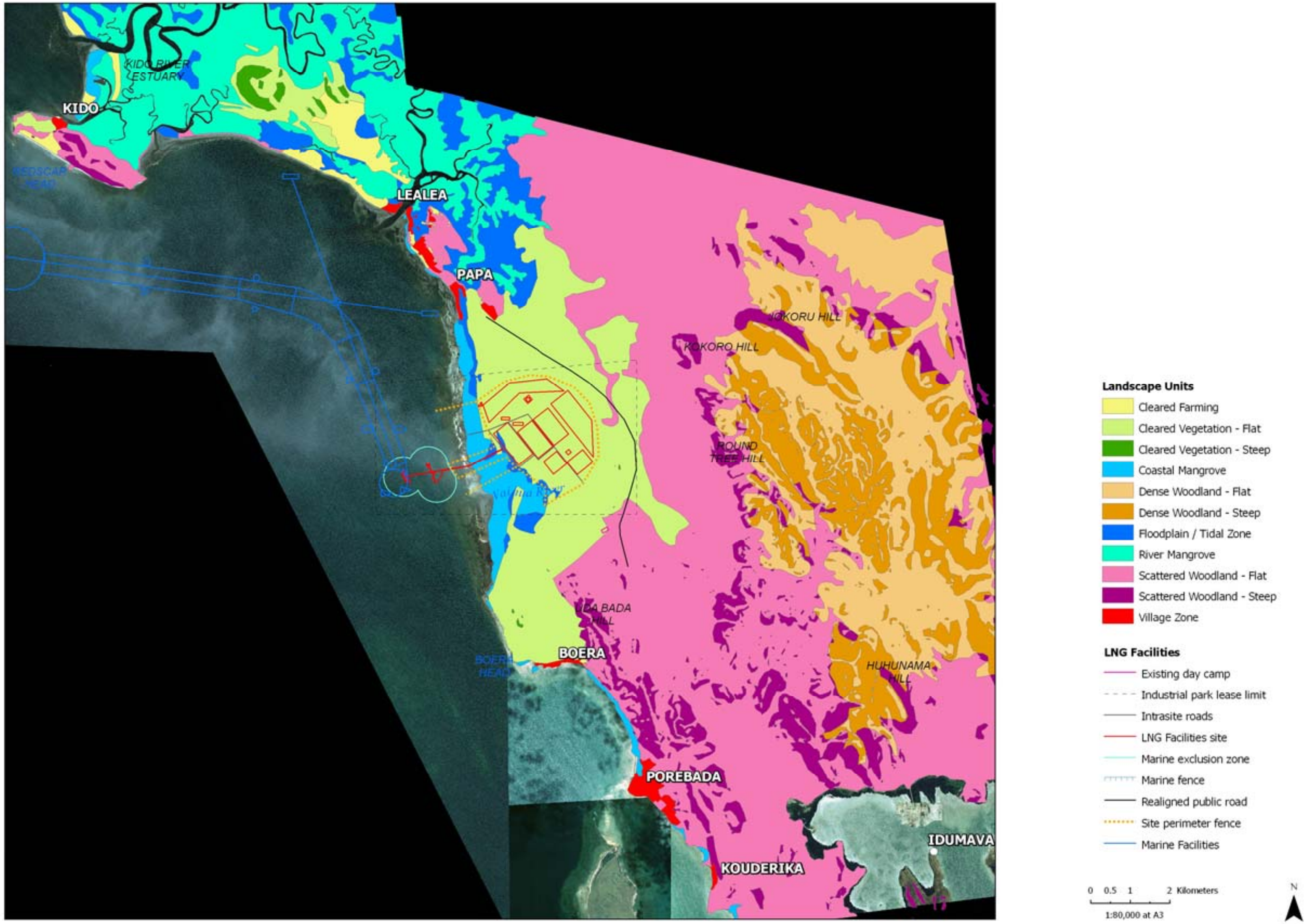


Figure 2.4: Landscape character units

2.5 Absorptive Capability

The definition of landscape absorptive quality is closely related to that of visual modification levels. It is generally applied at a broader scale than visual modification and is an assessment of how well a landscape setting is able to accommodate change or a development.

The key factors considered in determining absorptive capability are topography and vegetation. In areas of flatter topography, overlooking is not possible and a quite low and thin band of vegetation is able to screen views to a development from a given viewpoint. In areas of undulating or elevated topography, overlooking can occur and vegetation needs to be higher and denser to achieve effective screening. Intervening undulating topography also has the potential to block views in certain landscapes.

The landscape settings of the site and its sub regional and regional surroundings (the primary areas subject to visual impact) have the following absorptive capabilities;

2.5.1 Local Setting

The landscape within the local setting is generally flat and the lack of intervening vegetation to screen views limits the ability of the setting to absorb change.

Few viewing locations exist within the local setting.

2.5.2 Sub Regional Setting

The landscape within the near sub-regional setting is generally flat and the lack of intervening vegetation to screen views limits the ability of the setting to absorb change.

Within the distant sub-regional setting, increasing density of vegetation and topographic variation increases the absorptive capability of the setting.

A number of viewing locations exist within the sub-regional setting.

2.5.3 Regional Setting

To the south and east the topography increases in elevation with slopes varying from 20% to greater than 30%. Therefore, in these locations, the potential for overlooking increases, reducing absorptive capability. However, viewing locations with potential for overlooking are sparse. Vegetation density and height also increases in these locations which reduces the potential for overlooking views and increases absorptive capability.

3

3. Description of the Form of the Proposed LNG Facility

The proposed facility is comprised of a number of large scale elements.

3.1 Broad Description of the Project

Preliminary studies estimate that the footprint of the LNG Facility, including the plant, camp and all associated infrastructure is likely to be approximately 810ha. Construction of the LNG facilities and associated infrastructure is anticipated to take approximately 49 months, including site preparation and facilities commissioning. (Refer to Figures 3.1 and 3.2).

3.2 Components of the Project

The development is comprised of the following major components:

- LNG Plant.
- Gas Pipeline Shore Crossing.
- Staff Camp – Permanent and Temporary Construction.
- LNG Jetty, Export Terminal and Materials Offloading Facility (MOF).
- LNG Carriers and tugs.
- Gas Flare.
- Associated Infrastructure.

Refer to Figure 3.1: Indicative layout of facility.

3.2.1 The LNG Plant

The LNG plant is located onshore, and is the largest and most visible component of the proposed development. It is comprised of the production train as well as two 165,000m^3 storage tanks approximately 32.5m in height. The tallest elements of the plant are five stacks which are 50m in height and contained within the LNG Facility site.

3.2.2 Gas Pipeline Shore Crossing

The shoreline crossing of the gas pipeline occurs immediately to the north of the LNG jetty. The construction method is proposed to be open cut and the pipeline is proposed to be 34 inch diameter. This will require the excavation of a trench, an adjacent pipe lay down and construction area, construction access track and soil stockpiles prior to back filling.

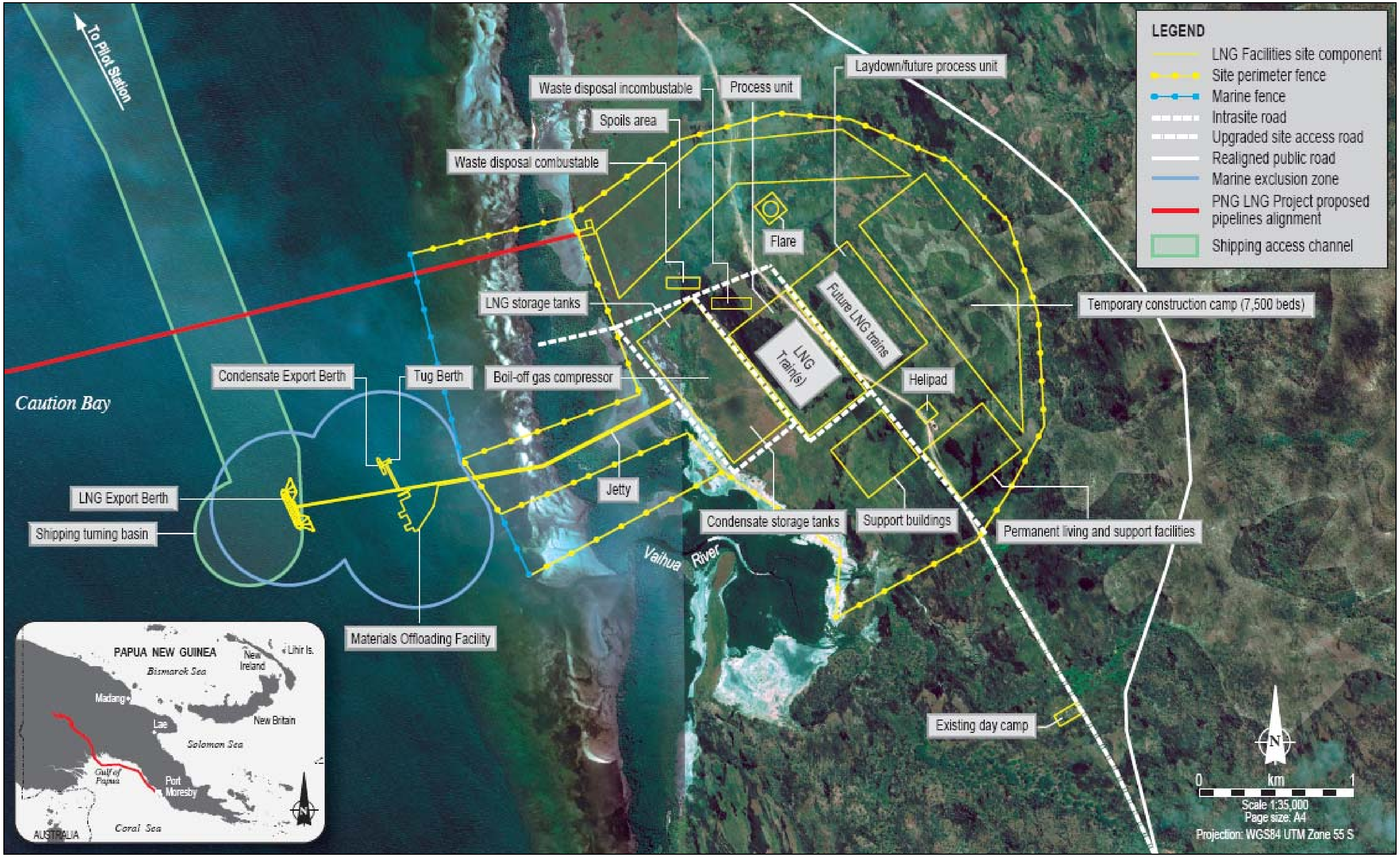


Figure 3.1 – Indicative layout of facility.

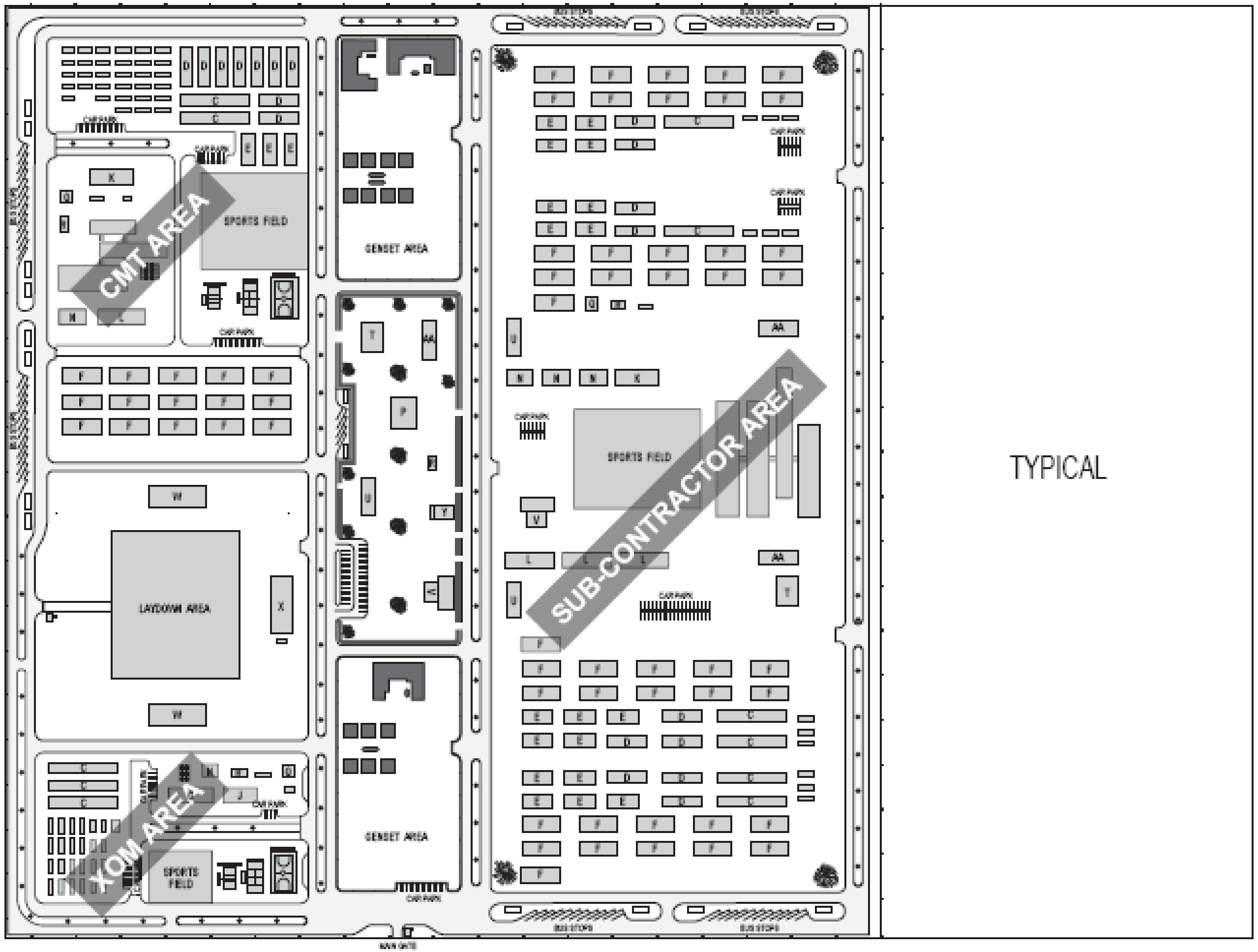
Figure 3.2 – Example of similar LNG facility - Darwin LNG Facility (Source: www.darwinlng.com).

3.2.3 Staff Camps

TEMPORARY CONSTRUCTION CAMP

A temporary camp for construction and contract personnel (approximately 7,500 people) will be established. (Refer to Figures 3.3 and 3.4). It will be comprised of:

- Accommodation units.
- Field site offices.
- Amenities – Church, Gym etc.
- Warehousing.
- Fuel storage.
- Fire Station
- Maintenance / workshops.
- Playing fields



Legend Schedule of Building

NO	DESCRIPTION	TOTAL QTY.
A	VIP accommodation	24
B	SR staff accommodation	46
C	SR 24 man dorm	11
D	JR 24 man dorm	19
E	OCN supervisor (56 man)	21
F	OCN workers (98 man)	58
G	XOM Kitchen/diner	1
H	CMT Kitchen/diner	1
I	SUBS Kitchen/diner	1
J	XOM recreation	1
K	SR/JR recreation	2
L	Recreation worker	4
M	Laundry unit (XOM)	1
N	Laundry unit (CMT/SUBS)	3
O	First aid	3
P	Clinic	1
Q	Camp office building	3
R	Maintenance workshop	4
S	Security office/guard house	7
T	Safety training/orientation building	2
U	Commissary/bank/post office/office	3
V	Fire station	2
W	Warehouse	2
X	Warehouse in office	1
Y	Fuel filling station	1
Z	Toilet	4
AA	Worship facility	3

Figure 3.3 – Typical 7,500 man camp set-out plan (Source: Coffey Natural Systems).

Figure 3.4 – Example of similar temporary construction camp facility at Tangguh (Source: Exxon Mobil).

PERMANENT LIVING AND SUPPORT FACILITES

An operations camp for operating and maintenance personnel to accommodate approximately 500 people is required in close proximity to the LNG facility. (Refer to Figure 3.1).The camp will be comprised of:

- 200 x 30m^2 accommodation units.
- Amenities
- Sports and recreation facilities.
- Playing field.

3.2.4 LNG Jetty, Export Terminal and Materials Offloading Facility (MOF)

The LNG jetty is proposed to be a piled access trestle offshore, with an earthen causeway connection across the salt pan, with a total length of approximately 2.6 km. (Refer to Figure 3.1). The trestle and causeway will support a range of facilities that could include an access way with sidewalks, LNG and vapour return lines, condensate loading lines and all related utilities and offsites to the product loading platforms.

The LNG loading platform, consisting of one LNG loading berth and return vapour arms, will be sited at the end of the jetty. A condensate loading platform will be sited near the mid point of the trestle.

The marine facilities will also include four tug berths and one crewboat berth.

The structure will be generally low profile and of a recessive light to mid grey colour.

An MOF is proposed to be located approximately half way along the LNG Jetty. The facility is proposed to be an earthen causeway with an offloading platform located to the south of the Jetty.

3.2.5 LNG Carriers and Tugs

LNG carriers with a capacity of up to 216,000m^3 will frequent the LNG jetty on a regular basis – once every 3 – 6 days depending on size. Given their size, up to 315m long, they will be highly visible elements, both day and night, located off the coast. Lighting will be required for Occupational Health and Safety (OH&S) and crew amenity purposes.

Four tugs up to 30m in, length will be required to assist the tankers to and from the jetty.

3.2.6 Gas Flare

Flaring of gas from the facility will be required from an operational production perspective. Although a relatively small component in the overall LNG plant, given the height of the stack at approximately 30m, the flare is potentially visible from a significant distance at night.

3.2.7 Associated Infrastructure

Associated infrastructure at the LNG facility site will include:

- Waste and effluent collection/treatment system.
- Administration and maintenance buildings associated with the LNG Facility.
- Warehouse - a minimum 3500m^2 warehouse facility will be required to support the LNG Plant operations. The warehouse design will also include, approximately:
  - 200m^2 of offices/workspace for 15 to 20 warehousing staff and contractors
  - 400m^2 of climate controlled storage
  - 4000m^2 of outdoor storage and laydown area in addition to the 3500m^2 warehouse facility
- Helipad.
- Upgrade of an existing road between the site and Port Moresby and realignment around the LNG facility site.

3.2.8 Lighting

The facility, camps and the loading jetty will operate 24 hours a day. It will therefore be illuminated from both an occupational health and safety perspective as well as for security reasons.

3.3 Duration of Construction and Operational Life

The project is expected to have a construction period of 49 months to first shipment. The program for the construction of the key elements would be:

- LNG Plant – 44 months
- Jetty – 38 months
- MOF – 12 months
- Construction (Pioneer) Camp – 4 months (and maintained for the duration of the construction program).
- Workers Camp – 25 months

The facility is expected to have an operational life of 30 years.

3.4 Summary of Area of Disturbance

The area that the various components of the project will require is summarised in the following table and outlined in greater detail in Appendix F.

Component	Dimensions (m)	Footprint Area (ha)
LNG plant / process unit	550 x 1,000	55
Staff camp - Construction	850 x 850	74
Permanent living and support	400 x 500	20
LNG tanks and condensate storage	1,200 x 550	66
Support buildings	400 x 400	16
Flare Area	200 x 200	4

Table 3.1: Areas of disturbance of major elements of the development.

3.5 Construction impacts

During the 49 month period of construction, the potential level of visual impact will progressively increase in relation to the extent of works.

The most immediate impact will result from the site clearing and grading process which will eventually cover an area in excess of 800ha.

As taller elements are progressively constructed the extent of area from which the development will be seen will progressively increase.

The temporary construction camp, with its large footprint and numerous buildings will be highly conspicuous. Given its temporary nature, landscape treatments will be ineffective in ameliorating visual impacts. By contrast, the permanent living and support facilities will be better integrated within the setting due to the ability to implement long term landscape amelioration and resident focused enhancements.

4

4. Assessment of Impact

The visual impact of the proposed facility has been assessed quantitatively and qualitatively for key sensitive viewpoints and land uses.

4.1 Visual Impact – Primary Viewpoints

The critical issues to consider in the assessment of visual impact are:

- Number of sensitive viewing locations.
- Degree to which the proposed works are visible. The method assumes that if the works are not seen, then there is no resulting impact.

Ten viewpoints located within a range of viewing settings, local, subregional and regional, were chosen for detailed assessment based on their levels of viewer sensitivity being higher than surrounding locations.

4.2 Viewshed

The viewshed or Zone of Visual Influence (ZVI) is the area from which views of a particular proposed development may be possible. The viewshed of the study area is shown in Figure 4.1.

The ZVI is considered to be a worst case scenario, with a greater extent of viewshed identified than would actually exist, as it does not take into account the effects of screening of views by vegetation.

4.3 Quantitative Assessment - Sensitive Sites

The quantitative assessment process has focussed on the visual impact that may result on views for the most sensitive visual settings / land uses, applying the visibility method as described in Appendix A. (Refer to Table 4.1). The results of the quantitative assessment assist in the determination of the level of visual modification. (Refer to Section 4.4 Qualitative Assessment). Low sensitivity visual settings, such as broadscale agricultural or forest areas, have not been considered. (Refer to Figure 4.2 for sensitive viewpoint locations). The quantification of vertical angle is based on the height of the tallest element of the proposed LNG facility, i.e., the trains.

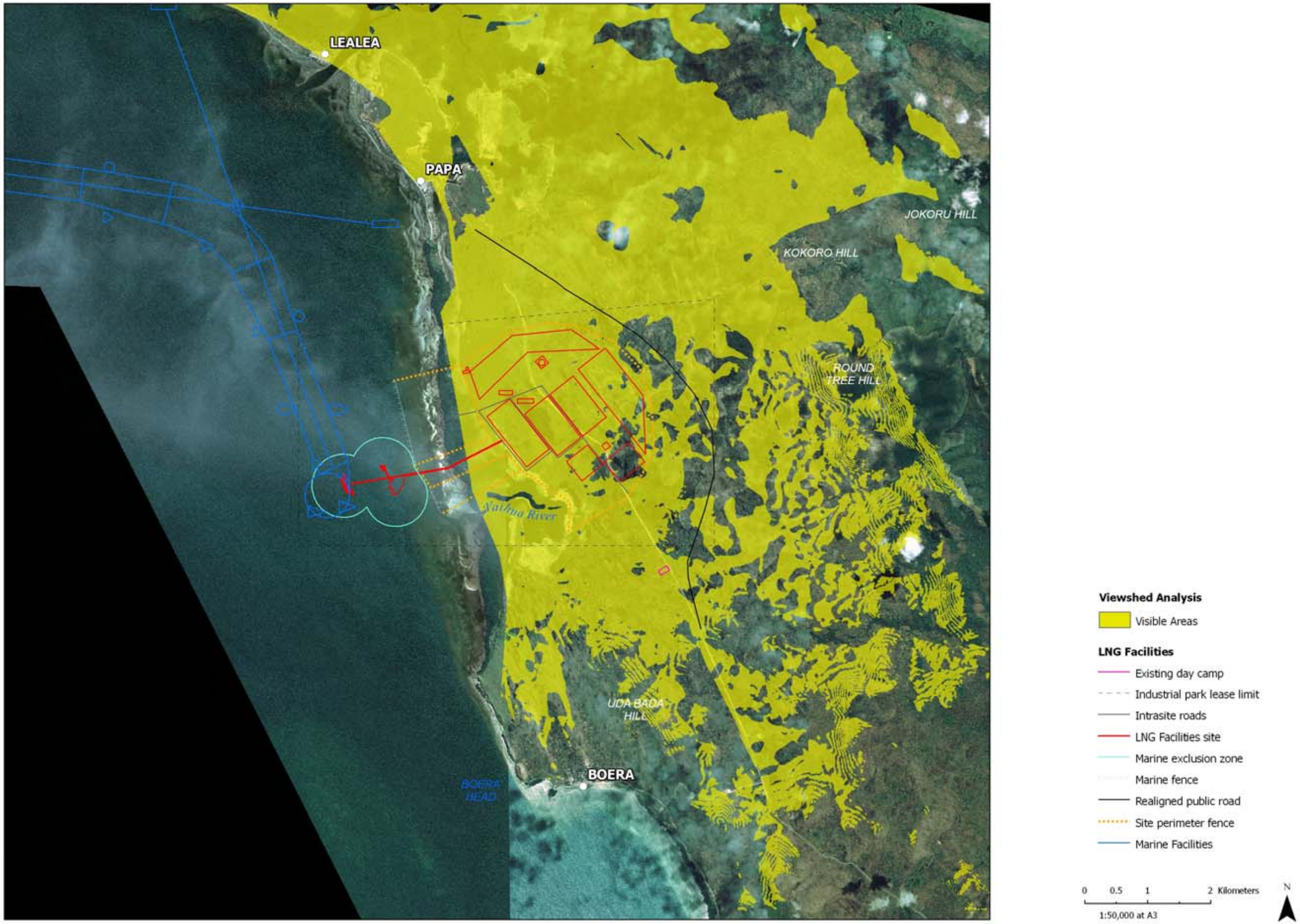


Figure 4.1: Viewshed / ZVI and Key Sensitive Viewpoints

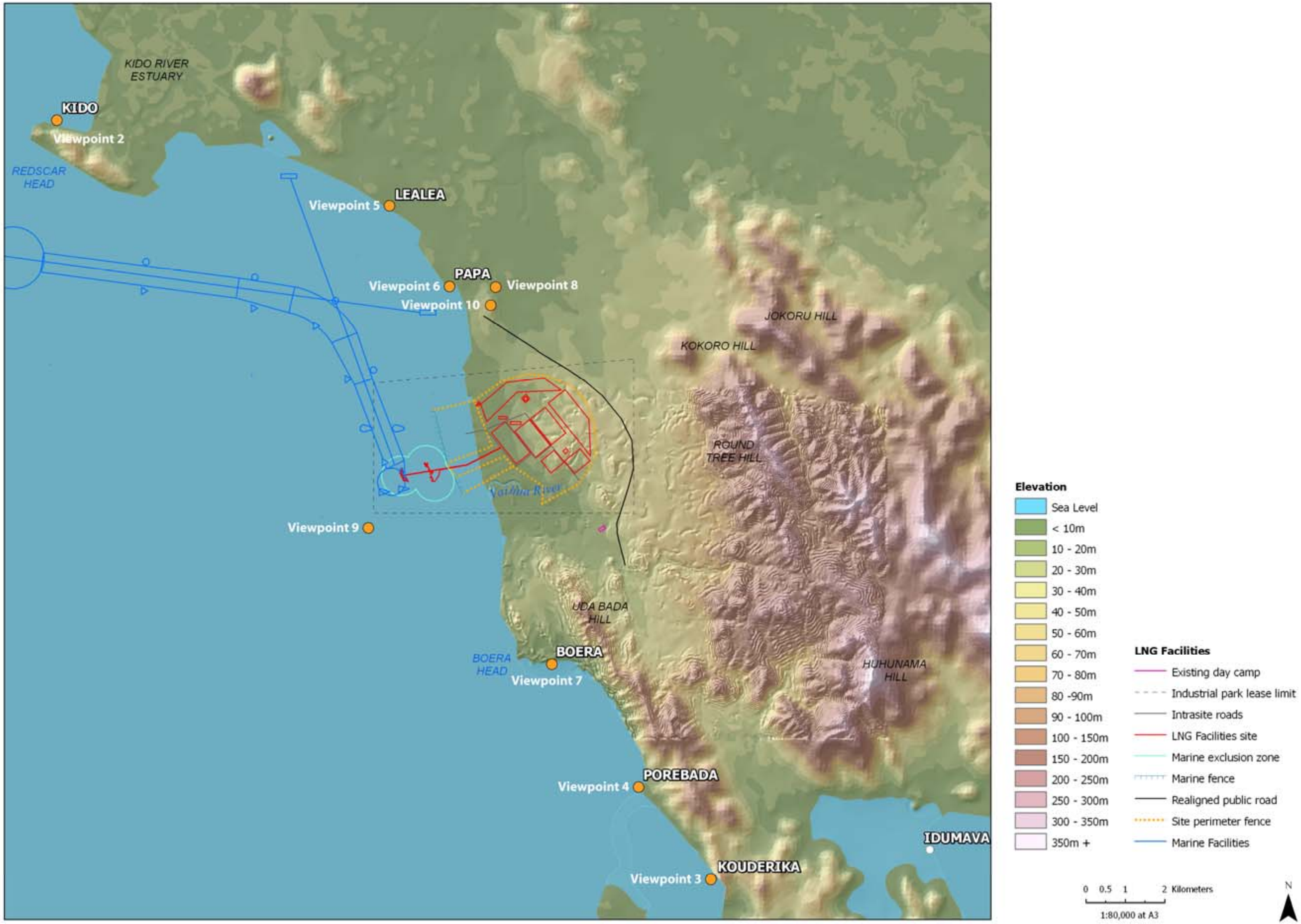


Figure 4.2: Viewpoint location map – All viewpoints.

Viewpoint	**Viewshed**	**Horizontal Distance from Viewer** - to facility at its closest	**Horizontal Angle** ***(Refer Table 1.1)***	***Horizontal*** ***Potential Visual Prominence***	**Vertical Angle** ***(Refer Table 1.2)***	***Vertical*** ***Potential Visual Prominence***
Viewpoint 1 Port Moresby	Regional	21 km	Not Visible	No Impact	Not Visible	No Impact
Viewpoint 2 Kido	Regional	12 km	Not visible from village centre	No Impact	Not visible from village centre	No Impact
Viewpoint 3 Kouderika	Regional	9.2 km	Not visible from village centre	No Impact	Not visible from village centre	No Impact
Viewpoint 4 Porebada	Regional	6.1 km	Not visible from village centre	No Impact	Not visible from village centre	No Impact
Viewpoint 5 Lea Lea	Regional	6 km	15^{o} Vegetation screening of inland components. Exposed views of jetty from offshore areas and shoreline.	Potentially Noticeable	1^{o}	Potentially Noticeable

Table 4.1: Quantitative Assessment – Sensitive Sites

Viewpoint	**Viewshed**	**Horizontal Distance from Viewer** - to facility at its closest ***(Refer Table 1.5)***	**Horizontal Angle** ***(Refer Table 1.3)***	***Horizontal Potential Visual Prominence***	**Vertical Angle** ***(Refer Table 1.4)***	***Vertical Potential Visual Prominence***
Viewpoint 6 Papa Papa	Sub - Regional	3.8 km	20^{o} Some vegetation screening of inland components. Exposed views of Jetty from offshore areas and shoreline.	Potentially Noticeable	$0.5 - 1^{o}$	Potentially Noticeable
Viewpoint 7 Boera	Sub - Regional	2.4 km	Not visible from village centre	No Impact	Not visible from village centre	No Impact
Viewpoint 8 Metago Bible College	Sub - Regional	2.4 km	80^{o}	Potentially Dominant	1.5^{o}	Potentially Noticeable
Viewpoint 9 Intertidal zone	Local	< 1 km	$> 30^{o}$ Vegetation starts to screen views parallel to shoreline as distance increases.	Potentially Dominant	$> 2.5^{o}$	Potentially Dominant
Viewpoint 10 Realigned Coastal Road	Local	< 1 km	$> 30^{o}$	Potentially Dominant	$> 2.5^{o}$	Potentially Dominant

Table 4.1: Quantitative Assessment – Sensitive Sites (cont)

4.4 Qualitative Assessment

The following section assesses the perceptual responses of viewers to visual change. Viewpoint locations, apart from Port Moresby, are shown in Figure 4.2. The assessment of impacts for viewpoints throughout the visual setting of the proposed LNG facility for the period up its completion, including construction – Pre-Mitigation Visual Impact, as well as for a period 5 years after completion of mitigation treatments – Post Mitigation or Residual Visual Impact, have been assessed.

4.4.1 Regional Setting

VIEWPOINT 1- PORT MORESBY

Viewing Situation	Elevated locations of city centre.
Viewing Distance	20 km.
Visual Setting	Regional.
Landscape Character	The setting of the main town is highly modified and includes port facilities and oil terminals. (Refer to Figure 4.3).
Land Use	Commercial, industrial, residential, retail.
Visual Modification	No apparent modification.
Visual Sensitivity	Very low.
Pre-Mitigation Visual Impact	None, as the site will not be visible from this location.
Residual Visual Impact	None, as the site will not be visible from this location.

Figure 4.3: Character of setting – Port Moresby.

VIEWPOINT 2 - KIDO

Viewing Situation	Kido village.
Viewing Distance	12 km.
Visual Setting	Regional.
Landscape Character	The village is located to the north of a steep, isolated headland in an otherwise low lying coastal plain. (Refer to Figure 4.4). Dense vegetation fringes the coastline.
Land Use	Village and associated garden plots.
Visual Modification	No apparent modification.
Visual Sensitivity	Low, due to distance from the site.
Pre-Mitigation Visual Impact	There will be no impact for the Village centre as the facility will not be visible. Views may be possible of the LNG jetty through vegetation from high points on the headland to the southeast of the village. The potential visual impact for these views will be low.
Residual Visual Impact	No impact for views from Village centre. Low for views of the LNG jetty from the headland as mitigation options will be limited.

Figure 4.4: Character of setting- View from Papa Papa beach to headland near Kido.

Figure 4.5: Viewpoint location map.

VIEWPOINT 3 - **KOUDERIKA**

Viewing Situation	From village centre.
Viewing Distance	9.2 km.
Visual Setting	Regional.
Landscape Character	Steep, lightly treed coastal headlands and rolling internal hills surround the village, enclosing views. (Refer to Figure 4.6).
Land Use	Village and associated garden plots.
Visual Modification	No apparent modification.
Visual Sensitivity	Low due to distance from the site.
Pre-Mitigation Visual Impact	There will be no impact for the village as the facility will not be visible.
Residual Visual Impact	No impact.

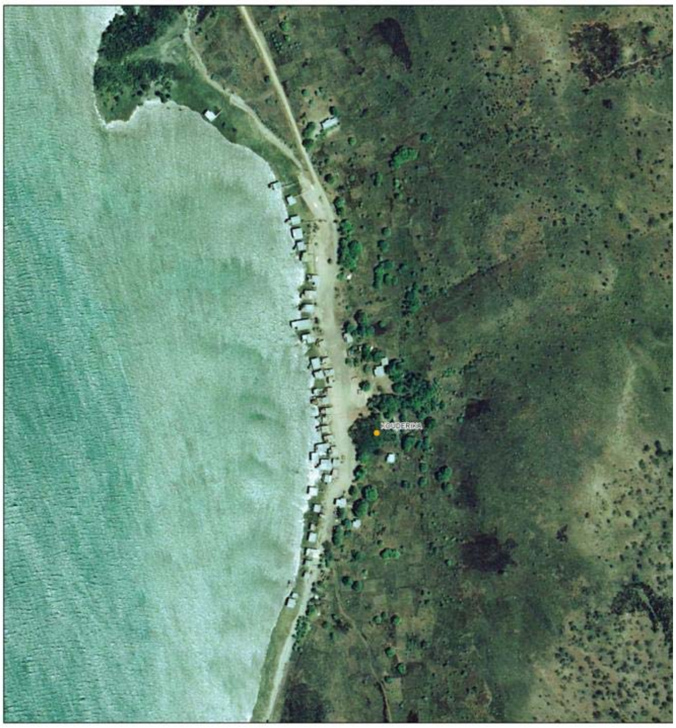


Figure 4.6: Character of setting – Village adjacent to beach with rising topography inland screening views.

Figure 4.7: Viewpoint location map.

VIEWPOINT 4 - POREBADA

Viewing Situation	Village centre.
Viewing Distance	6.1 km.
Visual Setting	Regional.
Landscape Character	Steep, lightly treed coastal headlands and rolling hills surround the village, enclosing views. (Refer to Figure 4.8). Boera headland in the distance provides further topographic screening of views.
Land Use	Village and associated garden plots.
Visual Modification	No apparent modification.
Visual Sensitivity	Low due to distance.
Pre-Mitigation Visual Impact	There will be no impact for the village as the facility will not be visible.
Residual Visual Impact	No impact.

Figure 4.8: Character of setting – Village located on coastal flat off low headland.

Figure 4.9: Viewpoint location map.

VIEWPOINT 5 - LEA LEA

Viewing Situation	From the beach, adjacent to houses in the northern part of the village.
Viewing Distance	6 km.
Visual Setting	Regional.
Landscape Character	The setting is characterised by coastal fringing mangroves with taller vegetation consisting primarily of coconut palms along sandy beaches and between the village houses. The village is drawn out along the main access road. The river divides the village, with most houses located to the south. (Refer to Figures 4.10 and 4.11).
Land Use	Village houses with associated gardens.
Visual Modification	Moderate due to screening of most on-shore elements by vegetation. (Refer to Figures 4.13 and 4.14).
Visual Sensitivity	Low due to distance.
Pre-Mitigation Visual Impact	The key visible elements from this location will be the LNG jetty and any attendant LNG carrier. Low, as the visible elements will contrast with the existing character of the visual setting.
Residual Visual Impact	Low as mitigation options for the LNG jetty will be limited.

Figure 4.10: Character of setting –Houses over look the estuary and coastline.

Figure 4.11: Closely spaced houses line the waters edge.

Figure 4.12: Viewpoint location map.

Figure 4.13: Existing view to site from North bank village of Lea Lea – Views to the on-shore components of the development will be screened by intervening topography.

Figure 4.14: Existing view to site from North bank village of Lea Lea along coastal edge– Views to the on-shore components of the development will be screened by intervening topography.

4.4.2 Sub–Regional Setting

VIEWPOINT 6 - **PAPA PAPA**

Viewing Situation	Adjacent to village on beach.
Viewing Distance	3.8 km.
Visual Setting	Sub Regional (Distant).
Landscape Character	The village is located on a low lying coastal strip. Mangroves line muddy intertidal zones, while palm trees are scattered throughout the village on sandy soils. (Refer to Figures 4.15 and 4.16).
Land Use	Village houses. Scattered gardens at the village perimeter.
Visual Modification	Moderate to High. On shore components will be generally screened by vegetation. Off-shore components such as the LNG Jetty and loading tankers will be highly visible and contrast with the setting at this distance.
Visual Sensitivity	Moderate.
Pre-Mitigation Visual Impact	The key visible elements from this location will be the LNG jetty and any attendant LNG carrier. Moderate to High, as the visible elements will contrast significantly with the existing character of the visual setting.
Residual Visual Impact	Moderate to High as mitigation options for the LNG jetty will be limited.

Figure 4.15: Character of setting – Few buildings are located immediately adjacent to the waters edge.

Figure 4.16: Character of setting – The village is clustered within scattered palms.

Figure 4.17: Viewpoint location map.

Figure 4.18: Existing view towards the proposed development site.

VIEWPOINT 7 - BOERA

Viewing Situation	Village Centre.
Viewing Distance	2.4 km.
Visual Setting	Sub Regional (Near).
Landscape Character	The village is located to the south east of a flat topped headland. Inland, topography rises steeply, separating the village from the broad plain on which the LNG facility is proposed. (Refer to Figure 4.19 and 4.20).
Land Use	Village houses. Scattered gardens at the village perimeter.
Visual Modification	No apparent modification.
Visual Sensitivity	High, however the site is not visible from the village centre.
Pre-Mitigation Visual Impact	None, as topography blocks views to the facility from the centre of the village. However, views will be possible through vegetation from high points to the north of the village, such as the headland. In this instance, the visual impact from these locations will be High.
Residual Visual Impact	No impact for views from the Village centre. High for views of the LNG jetty from the headland as mitigation options will be limited.

Figure 4.19: Character of setting – Densely grouped houses sit close to the waters edge.

Figure 4.20: Character of setting – The village lies south of Boera headland which visually screens views to the site.

Figure 4.21: Viewpoint location map.

Figure 4.22: Existing view towards proposed development site screened by topography and vegetation.

VIEWPOINT 8 – METAGO BIBLE COLLEGE

Viewing Situation	College Grounds.
Viewing Distance	2 km.
Visual Setting	Sub Regional (Near).
Landscape Character	The college is located on a low, grassed hill that is slightly elevated above the broad plain on which the proposed facility is to be located. (Refer to Figure 4.23).
Visual Modification	High due to the contrast between the components of the development and the landscape character of the setting. Visual exposure to the development is accentuated by overlooking.
Land Use	School – educational.
Visual Sensitivity	Moderate.
Pre-Mitigation Visual Impact	Overlooking of the site will be possible due to the slight elevation and the open landscape, which will allow expansive and exposed views. (Refer to Figure 4.26). Due to the proximity to the site, and the visual contrast between the LNG facility and the existing setting, the visual impact will be High.
Residual Visual Impact	Moderate to High as perimeter planting will be effective at screening views of less elevated elements.

Figure 4.23: Character of setting.

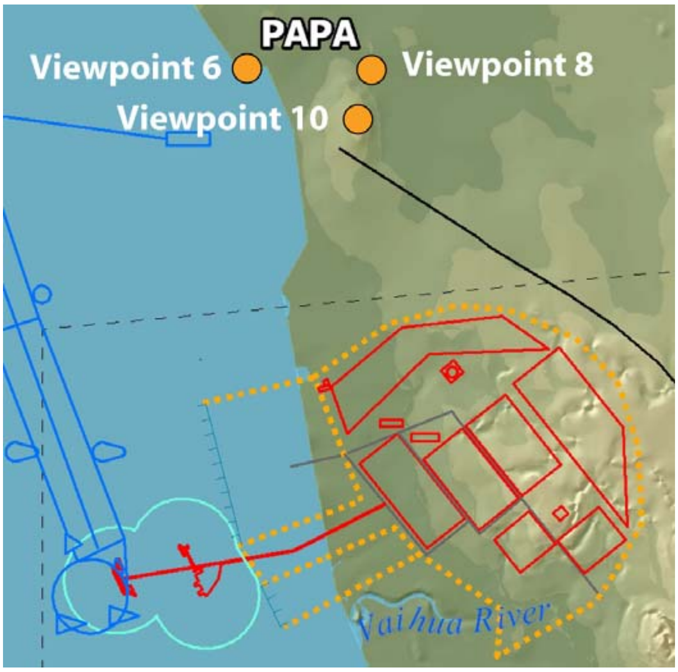


Figure 4.24: Viewpoint location map.

Figure 4.25: Existing view to proposed development site from southern boundary of college site.

Figure 4.26: Photosimulation of view to site from southern boundary of college site.

4.4.3 Local Setting

VIEWPOINT 9 – OFFSHORE AND INTERTIDAL ZONE

Viewing Situation	Adjacent to the proposed LNG facility at the coastal edge and offshore of the facility.
Viewing Distance	0 – 1 km.
Visual Setting	Local.
Landscape Character	From the low elevation viewing position of sea level, the dominant element in the landscape is the dense fringing band of mangroves to 8m in height that effectively block views into the ground plane of the proposed site. (Refer to Figures 4.27 and 4.29).
Land Use	Food collection and transport.
Visual Modification	High due to the scale of the components and their contrast with the existing setting.
Visual Sensitivity	The visual sensitivity of users will be Moderate.
Pre-Mitigation Visual Impact	The potential visual impact will be High due to the Moderate sensitivity of users and the visually dominant appearance of the facility including jetty at this distance. (Refer to Figure 4.30).
Residual Visual Impact	High as mitigation options for the LNG jetty will be limited.

Figure 4.27: Character of setting – Dense stands of mangrove line the inter-tidal zone.

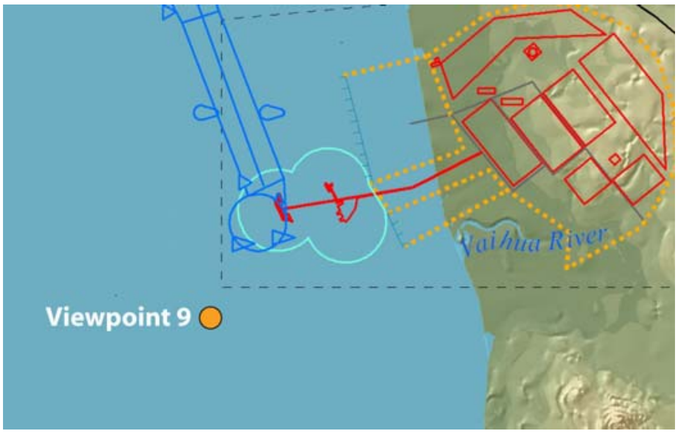


Figure 4.28: Viewpoint location map.

Figure 4.30: Photosimulation of view to site from approximately 1.3km offshore.

VIEWPOINT 10 – REALIGNED COASTAL ROAD

Viewing Situation	At the point where the existing coastal road will be realigned inland around the facilities perimeter.
Viewing Distance	1 km.
Visual Setting	Local.
Landscape Character	From road, the flat to gently undulating landscape of the open grassland dominates (Refer to Figure 4.31). The dense fringing band of mangroves along the coastline screen views to the ocean.
Land Use	Existing - Transport to / from Villages Proposed – Transport to and from Villages and the proposed LNG Facility.
Visual Modification	High due to the scale of the components and their contrast with the existing setting. Refer to Figure 4.34).
Visual Sensitivity	The visual sensitivity of users will be Low as the road is used by relatively low numbers of people travelling between their villages and Port Moresby.
Pre-Mitigation Visual Impact	The potential visual impact will be Moderate due to the Low sensitivity of users and the visually dominant appearance of the facility at this distance.
Residual Visual Impact	Low to Moderate as foreground screening vegetation will be effective at mitigating views.

Figure 4.31: Character of setting – Taller vegetation to the south of the site transitions to open grassland to the north which allows views across the site.

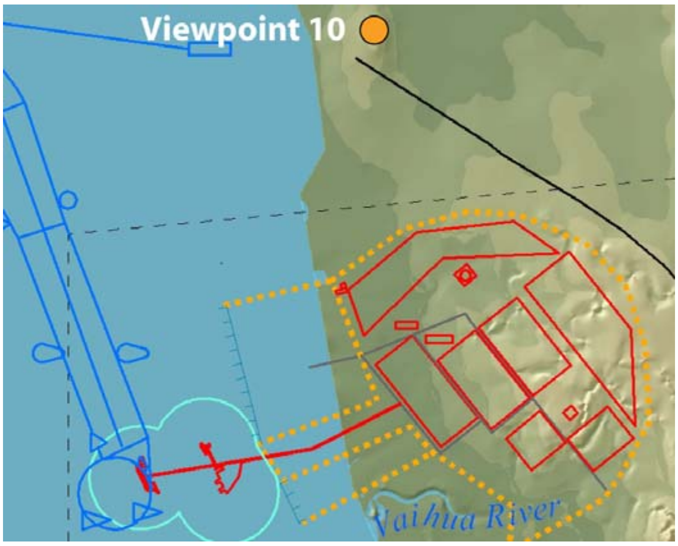


Figure 4.32: Viewpoint location map.

Figure 4.33: Existing view to site from point at which the realigned coastal road diverges from the existing road to the north of the proposed LNG facility.

Figure 4.34: Photosimulation of view to site from point at which the realigned coastal road diverges from the existing road to the north of the proposed LNG facility.

4.5 Impacts of Night Lighting

4.5.1 The Existing Setting

Apart from villages in the distant sub-regional and regional settings, the local setting is currently isolated from the effects of night lighting sources and is consistent with Environmental Zone E 1 – Intrinsically Dark Landscapes as identified in the Guidance Notes for Reduction of Light Pollution. The notes recommend that lighting within the identified zones should have minimal illumination into the sky as well as to adjacent viewpoints in order to maintain the night time setting.

4.5.2 Lighting Sources

The proposed development will be in use during both day and night. The lighting proposed to be employed on the proposed facility will be emitted from three sources:

FIXED / PERMANENT LIGHTS
This is lighting that is installed as part of the permanent infrastructure of the development, for example the main components of the facility, the internal access paths and roads and the perimeter security fencing. The primary types of lighting within this category are:

Security Lighting – Lighting of external fences, perimeter roads, the jetty and a 30m zone adjacent to it.

Operational lighting – Lighting of areas to facilitate operations and movement at night, for example, movement sensitive lighting in access areas and permanent lighting in areas where work activities are regularly undertaken.

Navigational Lighting – Lighting of the tallest elements of the facility to provide for aviation safety and navigation lighting of the jetty and associated mooring structure to provide for maritime safety.

VEHICLE MOUNTED LIGHTS
Vehicles operating within the development area will have headlights at night and occasionally hazard lights due to OH&S requirements.

FLARE
The flare associated with the venting of gas by – product will be located approximately 30m above ground level. It will be visually prominent in distant views due to its brightness and the movement / flicker of the flame.

4.5.3 Construction lighting

During the construction program, which is anticipated to be continuous, the primary lighting sources will be from work lights, security lights and construction vehicle lights.

4.5.4 Impacts of Lighting

From more distant locations, generally in the distant sub – regional setting, direct views to the lighting sources will be obscured from view by vegetation and undulating topography. A certain amount of light spill from the lighting may still occur above the intervening screening elements, particularly on nights when there is low cloud and reflection off the cloud base occurs.

Within the regional setting, for a limited number of sensitive locations such as villages, visible lighting is most likely to be a gentle glow without bright “spots”.

Apart from the relocated coastal access road, there are no sensitive viewing locations within the local setting. The access road will itself be a generator of lighting sources at night.

The exact impact or acceptability of night lighting is difficult to define as it is dependant on individual perceptions and sensitivities as well as the presence of existing light at the viewing source. However, as there are no other significant light sources in the regional setting apart from Port Moresby in the distance and the villages, a slight luminescence from the operations may be apparent in the sky when viewed from the regional setting. This could possibly result in a very minor visual intrusion to a very small number of viewers.

The effects of any lighting at the proposed facility will not generally be apparent from within the residences or villages at night when the internal house lights are on or from the immediate area around the residences or throughout the villages when external lighting is on.

Management of lighting spill will be more difficult during the construction process. However, the closet sensitive viewpoint to the site, the Papa School, will be unaffected as its operations are confined to daylight hours.

5

5. Conclusion

A key consideration in the assessment of visual impact will be the perception of local residents to change which brings improvements in lifestyle.

5.1 Perceptions of Change

Whilst the degree to which a development the scale of the proposed LNG facility is visible from certain vantage points can be quantified, the degree to which viewers from surrounding sensitive viewpoints will be impacted is influenced by an individual's perceptions of what change will bring.

Community expectations are addressed in a separate study and no assumptions have been made in this report in relation to local community expectations or perceptions to change. Therefore, the levels of viewer sensitivity that have been applied in this report are consistent with those applied on projects throughout Australia and other western countries, allowing for a high degree of sensitivity to change.

5.2 Visual Fit

In the context of the broader regional setting Port Moresby, and the industrial facilities to its north west between Port Moresby and the site, are consistent in terms of form and scale with the proposed LNG facility. However, within the sub–regional and local setting, there are no developments of a comparable scale or form.

Whilst the lack of substantial vegetation is a positive in terms of the minimisation of impact on flora and fauna, it also reduces the ability of the open and slightly undulating site and its immediate setting to visually mitigate the presence of the LNG Facility.

5.3 Night Lighting Impacts

There are no other significant light sources in the regional setting apart from Port Moresby in the distance and the villages, and a slight luminescence from the operations may be apparent in the sky when viewed from the regional setting which could possibly result in a very minor visual intrusion to a very small number of viewers.

Within the sub-regional setting, the effects of any lighting at the proposed facility will not generally be apparent from within the residences or villages at night when the internal house lights are on or from the immediate area around the residences or throughout the villages when external lighting is on.

Apart from the relocated coastal access road, there are no sensitive viewing locations within the local setting.

5.4 Construction Impacts

Prior to the completion of the project and the consolidation of the permanent facility areas, the impacts of construction will primarily be associated with the disturbance to surface vegetation, the presence of the stored construction materials and works compounds as well as the temporary workers camp. These impacts, although temporary, will exist for an extended period of time and will result in a high level of impact, primarily to the Metago Bible College and the users of the realigned coastal road. Minimisation of areas of disturbance will assist in the reduction of impact.

5.5 Summary of impact

The proposed LNG facility development will significantly change the landscape character of the local and sub regional setting. The impact that this will have on the relatively limited number of villages and people that will view it is dependant on how these people perceive the development. Is it a focal point that will result in associated economic and social benefits – a positive talisman of change, or is it something that negatively changes the way that they use or relate to their environment.

Regardless of the perceptions of the local community of the development, all reasonable efforts should be made to ameliorate the facility through planting and material selection.

Following is a summation of impacts for viewpoints throughout the visual setting of the proposed LNG facility for the period up its completion including construction – Pre-Mitigation Visual Impact - as well as for a period 5 years after completion of mitigation treatments – Post Mitigation or Residual Visual Impact.

Viewing Location	Sensitivity	Visual Modification Level	Pre – Mitigation Visual Impact	Residual Visual Impact
Regional Setting > 5km				
Viewpoint 1- Port Moresby	**VL**	**Not Visible**	**No Impact**	**No Impact**
Viewpoint 2 - Kido	**L**	**Not Visible**	**No Impact**	**No Impact**
Viewpoint 3 - Kouderika	**L**	**Not Visible**	**No Impact**	**No Impact**
Viewpoint 4 - Porebada	**L**	**Not Visible**	**No Impact**	**No Impact**
Viewpoint 5 – Lea Lea	**L**	**M**	**L - M**	**L - M**
Sub Regional Setting 0 – 5 km				
Viewpoint 6 – Papa Papa	**M**	**M - H**	**M - H**	**M - H**
Viewpoint 7 - Boera	**H**	**Not Visible**	**No Impact**	**No Impact**
Viewpoint 8 – Metago Bible College	**M - H**	**H**	**H**	**M - H**
Local Setting 0 – 1 km				
Viewpoint 9 - Offshore / Intertidal	**M**	**M - H**	**H**	**H**
Viewpoint 10 – Realigned Coastal Road	**L**	**H**	**M**	**L - M**
(H = High, M = Moderate, L = Low)				

Table 5.1 – Summary of Visual Impact

5.6 Recommended Mitigation Measures

The following mitigation measures are recommended to improve the visual fit of the proposed LNG facility into the landscape setting and reduce potential visual impacts.

5.6.1 Site Layout

The primary consideration in the amelioration of visual impact is siting. For example, setting the site inland, away from the flatter and visually open coastal zone, where the potential for backdropping or obscuring by topography exists would improve visual integration with the setting. However, this is not possible as an LNG plant needs to be located within 3kms of the point at which the pipeline emerges from the ocean as the liquefied gas turns gaseous once temperature increases.

5.6.2 Design of Structures

MASSING

Facility components will be placed according to safe constructibility and operations. However, any massing or grouping of components of the development will reduce the extent of ameliorative screening required and also reduce the extent of the area from which they will be seen.

In the case of off-shore elements, such as the LNG jetty, the slender, low profile design of the proposed structures assists in the reduction of visual prominence.

MATERIAL SELECTION
Colour

Given the facility will be backdropped by land in views from the primary sensitive viewing locations, buildings should be of a colour that is visually compatible with the surrounding landscape where appropriate, for example, olive or mid greens that are compatible with both the wet season greens and the dry season straw green / yellow.

Structures located within the setting of the ocean, such as the jetty and loading facilities should be coloured a mid grey where appropriate, so that they appear recessive in views.

5.6.3 Visual Screening

Community views regarding visual effects, which are raised through general ongoing public consultation during construction and operation may be dealt with via visual screening. Visual screening is most effective when employed at the site perimeter. Given the security requirement for views along the perimeter fence to be maintained, any amelioration treatment must be offset away from the fence to maintain a clear visual corridor.

SCREEN PLANTING

Screen planting is the most effective manner in which to provide amelioration up to significant heights. – 10 to 15 metres. This will provide screening to the majority of forms on the site. Taller elements, such as tanks and stacks will be dependant on material colour selection to reduce their visual impact.

VISUAL BUNDING

Earth mounding or bunding is an effective short term amelioration measure, as it blocks views immediately upon completion. The raw, earth-coloured appearance of mounding is very quickly replaced by the green of germinating cover plants, particularly in tropical locations.

In high rainfall event areas, consideration must be made to steepness of surface slope, to minimise erosion, and to drainage to ensure run – off is not interrupted.

A combination of visual bunding and screen planting can often provide the most effective visual amelioration response, as the bunding provides immediate screening of lower elements and the vegetation cover provides longer term screening.

5.6.4 Lighting

From an operational and security perspective, the perimeter and internal components of the LNG facility are required to be well illuminated. However, where practicable, treatments will be utilised to reduce light spill into the marine environment. Example treatments include:

FIXED / PERMANENT LIGHTS

Wherever practicable, fixed lighting should be both shielded and movement sensitive in order to reduce the potential for light spill, security considerations allowing.

VEHICLE MOUNTED LIGHTS

Vehicles operating within the main on-land components of the facility will generally have the glare from their lights screened from views from surrounding areas by ameliorative treatments surrounding the site perimeter.

5.6.5 Construction management

Many of the visual impacts associated with construction relate directly to the area of surface disturbance occurring to vegetation cover, as the colour contrast between soil and vegetation results in a high level of visual modification. Therefore, control of the extent of disturbance and rapid revegetation post construction are simple and effective measures to reduce impact.

Wherever practicable the detailed site layout and design process should endeavour to avoid tall trees and shrubs that have the potential to provide immediate screening to site elements. For example, minimise the removal of mangroves.

Re-establishment of surface vegetation on disturbed areas should be undertaken as soon as practicable following completion of construction.

APPENDIX A – Visibility Rationale

Visibility – Relationship with Viewsheds

The Landscape and Visual Impact Assessment report defines a number of viewsheds based on distance from the development for the purposes of assessment. The methodology is based on the reduction of impact with an increase in distance between a given viewpoint and the development. These viewsheds or settings are:

- **Local Setting** – up to 1km from the development
- **Sub Regional Setting** – between 1km and 5km from the development
- **Regional Setting** – beyond 5km of the development

These distances have been established based on previous studies undertaken by EDAW. They are based on the reduction of visibility of objects in the distance as the total field of view increases and the proportional field of view of a particular object reduces.

Horizontal Line of Sight

It is generally accepted that the central field of vision for the human eye covers a horizontal angle of approximately 50 degrees to 60 degrees. Given both eyes see simultaneously and that there is a degree of overlap, a central field of view results in a person looking straight ahead. ***(Refer to Figure A1).***

In the production of visual simulations, a 50mm lens on a 35mm film format is most widely used as it captures a field of view of approximately 46 degrees, similar to that of the view from one eye. Two photos taken with a 50mm lens produced as a panorama, with a degree of central overlap, capture the central field of view in a similar way to that of the human binocular view (binocular field).

Within the central field of vision, the viewed image is sharp, colours are separately defined and depth perception occurs.

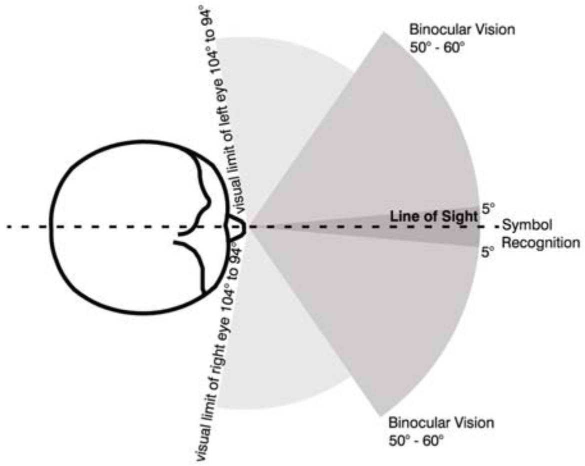


Figure A1 – Horizontal Line Of Sight

Visual Impact / Visual Prominence

The potential visual impact of a development will, to a large extent, depend on how much of the central field of vision that it occupies. In relation to the assessment of major infrastructure projects that often extend across the landscape, the calculation of horizontal view angle is not the only factor to be considered.

Degrees of Field of View Occupied	Potential Visual Prominence – Horizontal Field of View
Less than 5^o	***Insignificant*** The development will not be highly visible in the view, unless it contrasts strongly with the background.
5^o – 30^o	***Potentially Noticeable*** The development may be noticeable. The degree that it intrudes on the view will be dependant on how well it integrates with the landscape setting.
Greater than 30^o	***Potentially Dominant*** The development will be highly noticeable.

Vertical Line of Sight

As for the horizontal line of sight, there is also a vertical central field of view. If we assume that the horizon is 0^o then the eye clearly defines colour, field of view and has image sharpness for an angle of approximately 25^o upwards and 30^o downwards. However, in reality, the typical line of sight for a standing person at ground level is approximately 10^o below the horizon line. ***(Refer to Figure A2).***

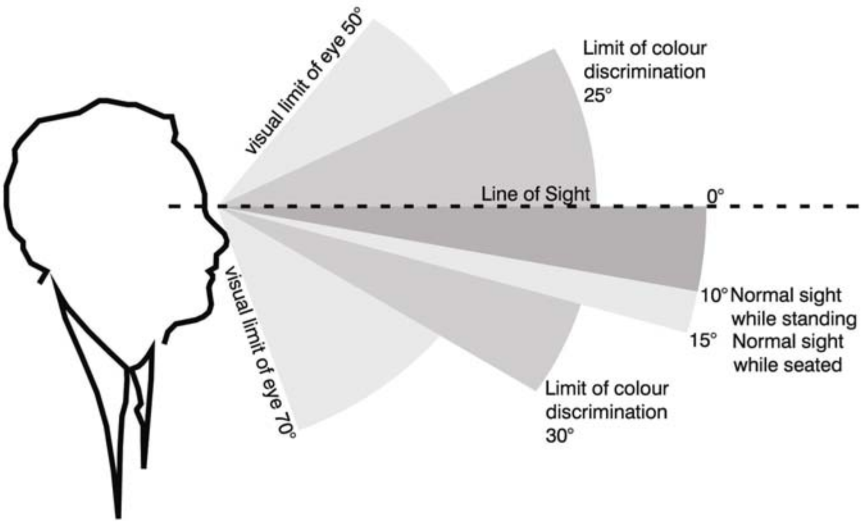


Figure A2 – Vertical Line Of Sight

Visual Impact / Visual Prominence
Objects that occupy a small proportion of the vertical field of view are visible but not dominant, particularly when they occur within landscapes that have been modified by human activity.

Degrees of Field of View Occupied	Potential Visual Prominence – Vertical Field of View
Less than 0.5°	***Insignificant*** A small thin line in the landscape.
0.5° – 2.5°	***Potentially Noticeable*** The development may be noticeable. The degree that it intrudes on the view will be dependant on how well it integrates with the landscape setting.
Greater than 2.5°	***Potentially Dominant*** The development will be highly noticeable, although the degree of visual intrusion will depend on the landscape setting and the width / thickness of the object.

Visual Prominence in Relation to Distance and Viewshed Settings

The following distances relating to visual prominence are based on the previous field of view exercises. The distances also relate to the distances for the setting types in the visual assessment methodology.

Distance from Object	Potential Visual Prominence
5000 metres	***Insignificant*** Visually insignificant.
1000 – 5000 metres	***Potentially Noticeable*** The development may be noticeable. The degree that it intrudes on the view will increase as distance reduces.
Less than 1000 metres	***Potentially Dominant*** The development will be highly noticeable.

Appendix B – Guidance Notes for the Reduction of Intrusive Light

Guidelines prepared by the Institution of Lighting Engineers, UK.

The Institution of Lighting Engineers

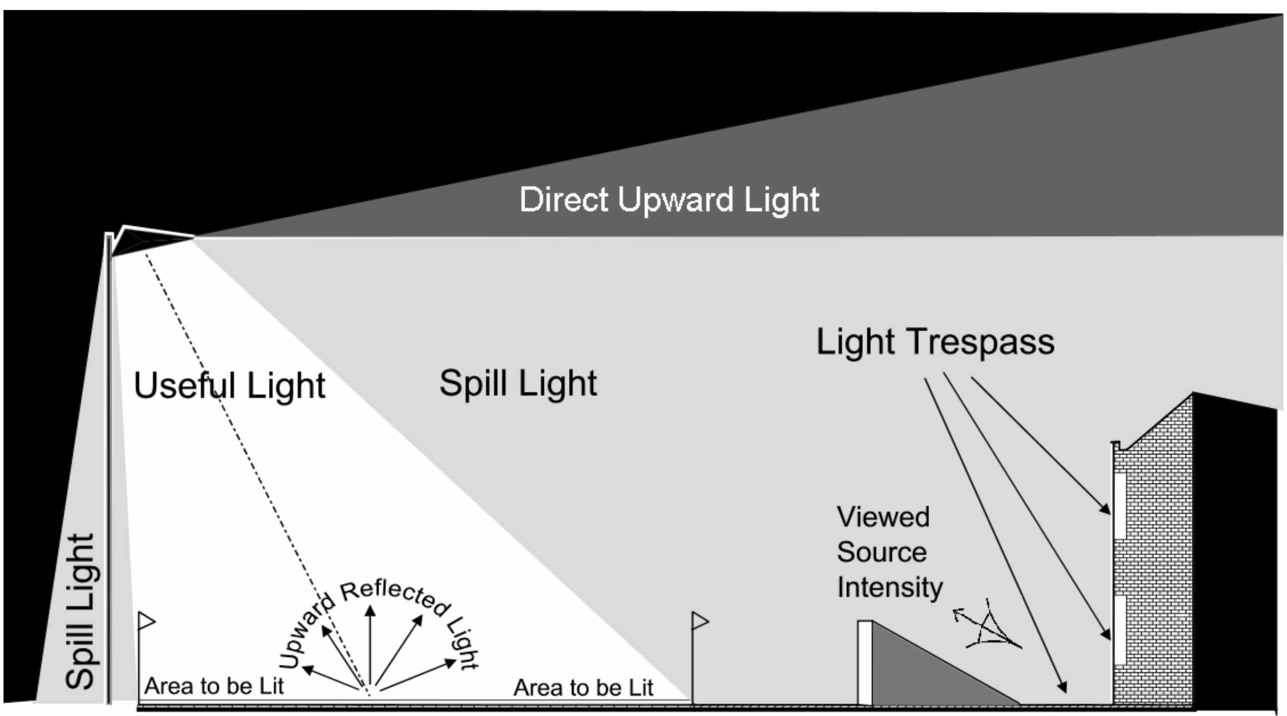
E-mail ile@ile.org.uk   Website www.ile.org.uk

GUIDANCE NOTES FOR THE REDUCTION OF OBTRUSIVE LIGHT

ALL LIVING THINGS adjust their behaviour according to natural light. Man's invention of artificial light has done much to enhance our night-time environment but, if not properly controlled, **obtrusive light** (commonly referred to as light pollution) can present serious physiological and ecological problems.

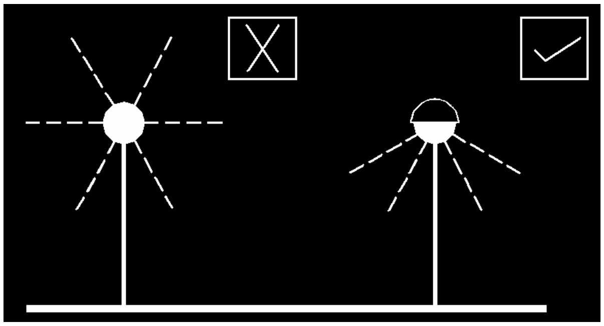
Obtrusive Light, whether it keeps you awake through a bedroom window or impedes your view of the night sky, is a form of pollution and can be substantially reduced without detriment to the lighting task.

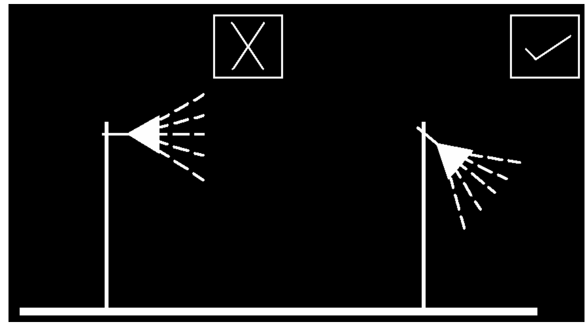
Sky glow, the brightening of the night sky above our towns, cities and countryside, **Glare** the uncomfortable brightness of a light source when viewed against a dark background, and **Light Trespass**, the spilling of light beyond the boundary of the property or area being lit, are all forms of obtrusive light which may cause nuisance to others, waste money and electricity and result in the unnecessary emissions of greenhouse gases. Think before you light. Is it necessary? What effect will it have on others? Will it cause a nuisance? How can I minimise the problem?



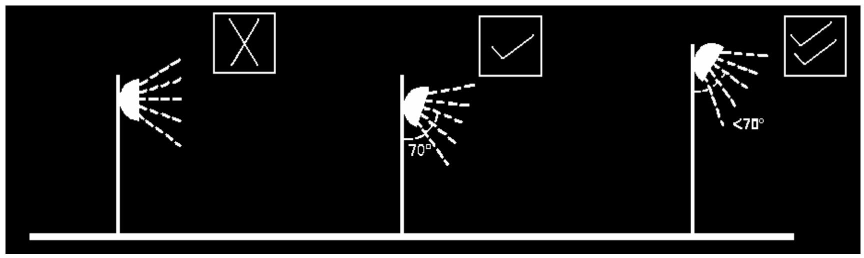
Do not "over" light. This is a major cause of obtrusive light and is a waste of energy. There are published standards for most lighting tasks, adherence to which will help minimise upward reflected light. Organisations from which full details of these standards can be obtained are given on the last page of this leaflet.

Dim or switch off lights when the task is finished. Generally a lower level of lighting will suffice to enhance the night time scene than that required for safety and security.



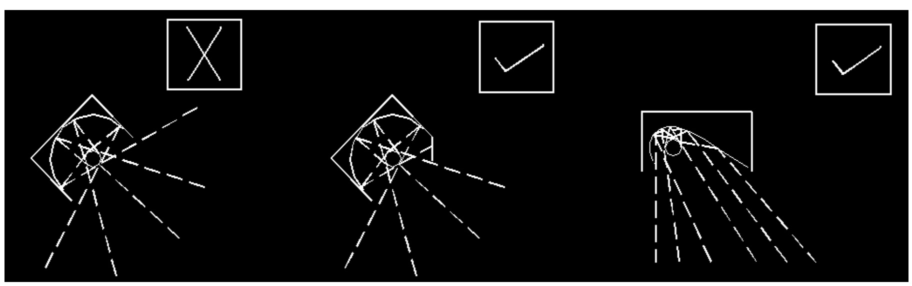


Use specifically designed lighting equipment that minimises the upward spread of light near to and above the horizontal. Care should be taken when selecting luminaires to ensure that appropriate units are chosen and that their location will reduce spill light and glare to a minimum. Remember that lamp light output in LUMENS is not the same as lamp wattage and that it is the former that is important in combating the problems of obtrusive light

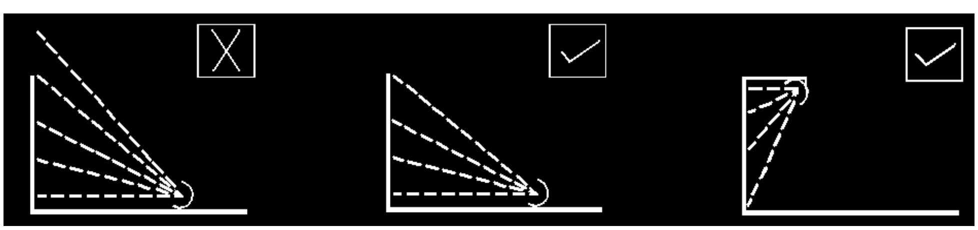


Keep glare to a minimum by ensuring that the main beam angle of all lights directed towards any potential observer is not more than 70°. Higher mounting heights allow lower main beam angles, which can assist in reducing glare. In areas with low ambient lighting levels, glare can be very obtrusive and extra care should be taken when positioning and aiming lighting equipment. With regard to domestic security lighting the ILE produces an information leaflet GN02 that is freely available from its web site.

The UK Government will be providing an annex to PPS23 Planning and Pollution Control, specifically on obtrusive light. However many Local Planning Authorities (LPA's) have already produced, or are producing, policies that within the new planning system will become part of the local development framework. For new developments there is an opportunity for LPA's to impose planning conditions related to external lighting, including curfew hours.



For sports lighting installations (see also design standards listed on Page 4) the use of luminaires with double-asymmetric beams designed so that the front glazing is kept at or near parallel to the surface being lit should, if correctly aimed, ensure minimum obtrusive light. In most cases it will also be beneficial to use as high a mounting height as possible, giving due regard to the daytime appearance of the installation. The requirements to control glare for the safety of road users are given in Table 2.



When lighting vertical structures such as advertising signs direct light downwards, wherever possible. If there is no alternative to up-lighting, as with much decorative lighting of buildings, then the use of shields, baffles and louvres will help reduce spill light around and over the structure to a minimum.

For road and amenity lighting installations, (see also design standards listed on Page 4) light near to and above the horizontal should normally be minimised to reduce glare and sky glow (Note ULRs in Table 1). In sensitive rural areas the use of full horizontal cut off luminaires installed at 0° uplift will, in addition to reducing sky glow, also help to minimise visual intrusion within the open landscape. However in many urban locations, luminaires fitted with a more decorative bowl and good optical control of light should be acceptable and may be more appropriate.

ENVIRONMENTAL ZONES:
It is recommended that Local Planning Authorities specify the following environmental zones for exterior lighting control within their Development Plans.

Category	Examples	
E1:	**Intrinsically dark landscapes**	National Parks, Areas of Outstanding Natural Beauty, etc
E2:	**Low district brightness areas**	Rural, small village, or relatively dark urban locations
E3:	**Medium district brightness areas**	Small town centres or urban locations
E4:	**High district brightness areas**	Town/city centres with high levels of night-time activity

Where an area to be lit lies on the boundary of two zones the obtrusive light limitation values used should be those applicable to the most rigorous zone.

DESIGN GUIDANCE
The following limitations may be supplemented or replaced by a LPA's own planning guidance for exterior lighting installations. As lighting design is not as simple as it may seem, you are advised to consult and/or work with a professional lighting designer before installing any exterior lighting.

Table 1 – Obtrusive Light Limitations for Exterior Lighting Installations

Environmental Zone	Sky Glow ULR [Max %] (1)	Light Trespass (into Windows) Ev [Lux] (2)		Source Intensity I [kcd] (3)		Building Luminance Pre-curfew (4)
		Pre- curfew	Post- curfew	Pre- curfew	Post- curfew	Average, L [cd/m2]
E1	0	2	1*	2.5	0	0
E2	2.5	5	1	7.5	0.5	5
E3	5.0	10	2	10	1.0	10
E4	15.0	25	5	25	2.5	25

ULR = **Upward Light Ratio of the Installation** is the maximum permitted percentage of luminaire flux for the total installation that goes directly into the sky.
Ev = **Vertical Illuminance in Lux** and is measured flat on the glazing at the centre of the window
I = **Light Intensity in Cd**
L = **Luminance in Cd/m2**
Curfew = **The time after which stricter requirements (for the control of obtrusive light) will apply**; often a condition of use of lighting applied by the local planning authority. If not otherwise stated - 23.00hrs is suggested.
* = From Public road lighting installations only

(1) **Upward Light Ratio** – Some lighting schemes will require the deliberate and careful use of upward light – e.g. ground recessed luminaires, ground mounted floodlights, festive lighting – to which these limits cannot apply. However, care should always be taken to minimise any upward waste light by the proper application of suitably directional luminaires and light controlling attachments.

(2) **Light Trespass (into Windows)** – These values are suggested maxima and need to take account of existing light trespass at the point of measurement. In the case of road lighting on public highways where building facades are adjacent to the lit highway, these levels may not be obtainable. In such cases where a specific complaint has been received, the Highway Authority should endeavour to reduce the light trespass into the window down to the after curfew value by fitting a shield, replacing the luminaire, or by varying the lighting level.

(3) **Source Intensity** – This applies to each source in the potentially obtrusive direction, outside of the area being lit. The figures given are for general guidance only and for some sports lighting applications with limited mounting heights, may be difficult to achieve.

(4) **Building Luminance** – This should be limited to avoid over lighting, and related to the general district brightness. In this reference building luminance is applicable to buildings directly illuminated as a night-time feature as against the illumination of a building caused by spill light from adjacent luminaires or luminaires fixed to the building but used to light an adjacent area.

Table 2 – Maximum Values of Threshold Increment from Non-Road Lighting Installations				
Light Technical Parameter TI	**Road Classification** [(5)]			
	No road lighting	ME5	ME4/ ME3	ME2 / ME1
	15% based on adaptation luminance of 0.1cd/m^2	15% based on adaptation luminance of 1cd/m^2	15% based on adaptation luminance of 2 cd/m^2	15% based on adaptation luminance of 5 cd/m^2

TI = **Threshold Increment** is a measure of the loss of visibility caused by the disability glare from the obtrusive light installation

(5) **Road Classifications** as given in BS EN 13201 - 2: 2003 Road lighting Performance requirements
Limits apply where users of transport systems are subject to a reduction in the ability to see essential information. Values given are for relevant positions and for viewing directions in path of travel. See CIE Publication 150:2003, Section 5.4 for methods of determination. For a more detailed description and methods for calculating and measuring the above parameters see CIE Publication 150:2003.

RELEVANT PUBLICATIONS AND STANDARDS:

British Standards: www.bsi.org.uk		BS 5489-1: 2003 Code of practice for the design of road lighting – Part 1: Lighting of roads and public amenity areas
		BS EN 13201-2:2003 Road lighting – Part 2: Performance requirements
		BS EN 13201-3:2003 Road lighting – Part 3: Calculation of performance
		BS EN 13201-4:2003 Road lighting – Part 4: Methods of measuring lighting performance.
		BS EN 12193: 2003 Light and lighting – Sports lighting
Countryside Commission/DOE www.odpm.gov.uk		Lighting in the Countryside: Towards good practice (1997) *(Out of Print)*
CIBSE/SLL Publications: www.cibse.org	CoL	Code for Lighting (2002)
	LG1	The Industrial Environment (1989)
	LG4	Sports (1990+Addendum 2000)
	LG6	The Exterior Environment (1992)
	FF7	Environmental Considerations for Exterior Lighting (2003)
CIE Publications: www.cie.co.at	01	Guide lines for minimizing Urban Sky Glow near Astronomical Observatories (1980)
	83	Guide for the lighting of sports events for colour television and film systems (1989)
	92	Guide for floodlighting (1992)
	115	Recommendations for the lighting of roads for motor and pedestrian traffic (1995)
	126	Guidelines for minimizing Sky glow (1997)
	129	Guide for lighting exterior work areas (1998)
	136	Guide to the lighting of urban areas (2000)
	150	Guide on the limitations of the effect of obtrusive light from outdoor lighting installations (2003)
	154	The Maintenance of outdoor lighting systems (2003)
Department of Transport www.defra.gov.uk		Road Lighting and the Environment (1993) (Out of Print)
ILE Publications: www.ile.org	TR 5	Brightness of Illuminated Advertisements (2001)
	TR24	A Practical Guide to the Development of a Public Lighting Policy for Local Authorities (1999)
	GN02	Domestic Security Lighting, Friend or Foe
ILE/CIBSE Joint Publications		Lighting the Environment - A guide to good urban lighting (1995)
ILE/CSS Joint Publications		Seasonal Decorations – Code of Practice (2005)
Campaign for Dark Skies (CfDS) www.dark-skies.org		

NB: These notes are intended as guidance only and the application of the values given in Tables 1 & 2 should be given due consideration along with all other factors in the lighting design. Lighting is a complex subject with both objective and subjective criteria to be considered. The notes are therefore no substitute for professionally assessed and designed lighting, where the various and maybe conflicting visual requirements need to be balanced.

Appendix C - Environmental, Health and Safety Guidelines for Onshore Oil and Gas Development

Guidelines prepared by the World Bank Group for funded projects.

Environmental, Health, and Safety Guidelines for Onshore Oil and Gas Development

Introduction

The Environmental, Health, and Safety (EHS) Guidelines are technical reference documents with general and industry-specific examples of Good International Industry Practice (GIIP)[1]. When one or more members of the World Bank Group are involved in a project, these EHS Guidelines are applied as required by their respective policies and standards. These industry sector EHS guidelines are designed to be used together with the **General EHS Guidelines** document, which provides guidance to users on common EHS issues potentially applicable to all industry sectors. For complex projects, use of multiple industry-sector guidelines may be necessary. A complete list of industry-sector guidelines can be found at: www.ifc.org/ifcext/enviro.nsf/Content/EnvironmentalGuidelines

The EHS Guidelines contain the performance levels and measures that are generally considered to be achievable in new facilities by existing technology at reasonable costs. Application of the EHS Guidelines to existing facilities may involve the establishment of site-specific targets, with an appropriate timetable for achieving them. The applicability of the EHS Guidelines should be tailored to the hazards and risks established for each project on the basis of the results of an environmental assessment in which site-specific variables, such as host country context, assimilative capacity of the environment, and other project factors, are taken into account. The applicability of specific technical recommendations should be based on the professional opinion of qualified and experienced persons. When host country regulations differ from the levels and measures presented in the EHS Guidelines, projects are expected to achieve whichever is more stringent. If less stringent levels or measures than those provided in these EHS Guidelines are appropriate, in view of specific project circumstances, a full and detailed justification for any proposed alternatives is needed as part of the site-specific environmental assessment. This justification should demonstrate that the choice for any alternate performance levels is protective of human health and the environment.

Applicability

The EHS Guidelines for Onshore Oil and Gas Development include information relevant to seismic exploration; exploration and production drilling; development and production activities; transportation activities including pipelines; other facilities including pump stations, metering stations, pigging stations, compressor stations and storage facilities; ancillary and support operations; and decommissioning. For onshore oil and gas facilities located near the coast (e.g. coastal terminals marine supply bases, loading / offloading terminals), additional guidance is provided in the **EHS Guidelines for Ports, Harbors, and Terminals.** This document is organized according to the following sections:

Section 1.0 — Industry-Specific Impacts and Management
Section 2.0 — Performance Indicators and Monitoring
Section 3.0 — References
Annex A — General Description of Industry Activities

[1] Defined as the exercise of professional skill, diligence, prudence and foresight that would be reasonably expected from skilled and experienced professionals engaged in the same type of undertaking under the same or similar circumstances globally. The circumstances that skilled and experienced professionals may find when evaluating the range of pollution prevention and control techniques available to a project may include, but are not limited to, varying levels of environmental degradation and environmental assimilative capacity as well as varying levels of financial and technical feasibility.

1.0 Industry-Specific Impacts and Management

This section provides a summary of EHS issues associated with onshore oil and gas development, along with recommendations for their management. These issues may be relevant to any of the activities listed as applicable to these guidelines. Additional guidance for the management of EHS issues common to most large industrial facilities during the construction phase is provided in the **General EHS Guidelines**.

1.1 Environment

The following environmental issues should be considered as part of a comprehensive assessment and management program that addresses project-specific risks and potential impacts. Potential environmental issues associated with onshore oil and gas development projects include the following:

- Air emissions
- Wastewater / effluent discharges
- Solid and liquid waste management
- Noise generation
- Terrestrial impacts and project footprint
- Spills

Air Emissions

The main sources of air emissions (continuous or non-continuous) resulting from onshore activities include: combustion sources from power and heat generation, and the use of compressors, pumps, and reciprocating engines (boilers, turbines, and other engines); emissions resulting from flaring and venting of hydrocarbons; and fugitive emissions.

Principal pollutants from these sources include nitrogen oxides, sulfur oxides, carbon monoxide, and particulates. Additional pollutants can include: hydrogen sulfide (H_2S); volatile organic compounds (VOC) methane and ethane; benzene, ethyl benzene, toluene, and xylenes (BTEX); glycols; and polycyclic aromatic hydrocarbons (PAHs).

Significant (>100,000 tons CO_2 equivalent per year) greenhouse gas (GHG) emissions from all facilities and support activities should be quantified annually as aggregate emissions in accordance with internationally recognized methodologies and reporting procedures.[2]

All reasonable attempts should be made to maximize energy efficiency and design facilities to minimize energy use. The overall objective should be to reduce air emissions and evaluate cost-effective options for reducing emissions that are technically feasible. Additional recommendations on the management of greenhouse gases and energy conservation are addressed in the **General EHS Guidelines.**

Air quality impacts should be estimated by the use of baseline air quality assessments and atmospheric dispersion models to establish potential ground level ambient air concentrations during facility design and operations planning as described in the **General EHS Guidelines**. These studies should ensure that no adverse impacts to human health and the environment result.

Exhaust gases

Exhaust gas emissions produced by the combustion of gas or liquid fuels in turbines, boilers, compressors, pumps and other engines for power and heat generation, or for water injection or oil and gas export, can be the most significant source of air emissions from onshore facilities. Air emission specifications should be considered during all equipment selection and procurement.

[2] Additional guidance on quantification methodologies can be found in IFC Guidance Note 3, Annex A, available at www.ifc.org/envsocstandards

Guidance for the management of small combustion source emissions with a capacity of up to 50 megawatt hours thermal (MWth), including air emission standards for exhaust emissions, is provided in the **General EHS Guidelines**. For combustion source emissions with a capacity of greater than 50 MWth refer to the **EHS Guidelines for Thermal Power.**

Venting and Flaring

Associated gas brought to the surface with crude oil during oil production is sometimes disposed of at onshore facilities by venting or flaring to the atmosphere. This practice is now widely recognized to be a waste of a valuable resource, as well as a significant source of GHG emissions.

However, flaring or venting are also important safety measures used on onshore oil and gas facilities to ensure gas and other hydrocarbons are safely disposed of in the event of an emergency, power or equipment failure, or other plant upset condition.

Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the World Bank Group's Global Gas Flaring Reduction Public-Private Partnership (GGFR program[3]) should be adopted when considering flaring and venting options for onshore activities. The standard provides guidance on how to eliminate or achieve reductions in the flaring and venting of natural gas.

Continuous venting of associated gas is not considered current good practice and should be avoided. The associated gas stream should be routed to an efficient flare system, although continuous flaring of gas should be avoided if feasible alternatives are available. Before flaring is adopted, feasible alternatives for the use of the gas should be evaluated to the maximum extent possible and integrated into production design. Alternative options may include gas utilization for on-site energy needs, export of the gas to a neighboring facility or to market, gas injection for reservoir pressure maintenance, enhanced recovery using gas lift, or gas for instrumentation. An assessment of alternatives should be adequately documented and recorded. If none of the alternative options are currently feasible, then measures to minimize flare volumes should be evaluated and flaring should be considered as an interim solution, with the elimination of continuous production-associated gas flaring as the preferred goal.

If flaring is necessary, continuous improvement of flaring through implementation of best practices and new technologies should be demonstrated. The following pollution prevention and control measures should be considered for gas flaring:

- Implementation of source gas reduction measures to the maximum extent possible;
- Use of efficient flare tips, and optimization of the size and number of burning nozzles;
- Maximizing flare combustion efficiency by controlling and optimizing flare fuel / air stream flow rates to ensure the correct ratio of assist stream to flare stream;
- Minimizing flaring from purges and pilots, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units, inert purge gas, soft seat valve technology where appropriate, and installation of conservation pilots;
- Minimizing risk of pilot blow-out by ensuring sufficient exit velocity and providing wind guards;
- Use of a reliable pilot ignition system;
- Installation of high integrity instrument pressure protection systems, where appropriate, to reduce over pressure events and avoid or reduce flaring situations;
- Minimizing liquid carry-over and entrainment in the gas flare stream with a suitable liquid separation system;

[3] World Bank Group (2004)

- Minimizing flame lift off and / or flame lick;
- Operating flare to control odor and visible smoke emissions (no visible black smoke);
- Locating flare at a safe distance from local communities and the workforce including workforce accommodation units;
- Implementation of burner maintenance and replacement programs to ensure continuous maximum flare efficiency;
- Metering flare gas.

In the event of an emergency or equipment breakdown, or plant upset conditions, excess gas should not be vented but should be sent to an efficient flare gas system. Emergency venting may be necessary under specific field conditions where flaring of the gas stream is not possible, or where a flare gas system is not available, such as a lack of sufficient hydrocarbon content in the gas stream to support combustion or a lack of sufficient gas pressure to allow it to enter the flare system. Justification for excluding a gas flaring system should be fully documented before an emergency gas venting facility is considered.

To minimize flaring events as a result of equipment breakdowns and plant upsets, plant reliability should be high (>95 percent) and provision should be made for equipment sparing and plant turn down protocols.

Flaring volumes for new facilities should be estimated during the initial commissioning period so that fixed volume flaring targets can be developed. The volumes of gas flared for all flaring events should be recorded and reported.

Fugitive Emissions

Fugitive emissions at onshore facilities may be associated with cold vents, leaking pipes and tubing, valves, connections, flanges, packings, open-ended lines, pump seals, compressor seals, pressure relief valves, tanks or open pits / containments, and hydrocarbon loading and unloading operations.

Methods for controlling and reducing fugitive emissions should be considered and implemented in the design, operation, and maintenance of facilities. The selection of appropriate valves, flanges, fittings, seals, and packings should consider safety and suitability requirements as well as their capacity to reduce gas leaks and fugitive emissions. Additionally, leak detection and repair programs should be implemented. Vapor control units should be installed, as needed, for hydrocarbon loading and unloading operations.

Use of open vents in tank roofs should be avoided by installing pressure relief valves. Vapor control units should be installed, as needed, for the loading and unloading of ship tankers. Vapor processing systems may consist of different units, such as carbon adsorption, refrigeration, thermal oxidation, and lean oil absorption units. Additional guidance for the prevention and control of fugitive emissions from storage tanks are provided in the **EHS Guidelines for Crude Oil and Petroleum Product Terminals**.

Well Testing

During well testing, flaring of produced hydrocarbons should be avoided wherever practical and possible, and especially near local communities or in environmentally sensitive areas. Feasible alternatives should be evaluated for the recovery of hydrocarbon test fluids, while considering the safety of handling volatile hydrocarbons, for transfer to a processing facility or other alternative disposal options. An evaluation of disposal alternatives for produced hydrocarbons should be adequately documented and recorded.

If flaring is the only option available for the disposal of test fluids, only the minimum volume of hydrocarbons required for the test should be flowed and well test durations should be reduced to the extent practical. An efficient test flare burner head equipped with an appropriate combustion enhancement system should be selected to minimize incomplete combustion, black smoke, and hydrocarbon fallout. Volumes of hydrocarbons flared should be recorded.

Wastewaters

The **General EHS Guidelines** provide information on wastewater management, water conservation and reuse, along with wastewater and water quality monitoring programs. The guidance below is related to additional wastewater streams specific to the onshore oil and gas sector.

Produced Water

Oil and gas reservoirs contain water (formation water) that is produced when brought to the surface during hydrocarbon production. The produced water stream can be one of the largest waste products, by volume, managed and disposed of by the onshore oil and gas industry. Produced water contains a complex mixture of inorganic (dissolved salts, trace metals, suspended particles) and organic (dispersed and dissolved hydrocarbons, organic acids) compounds, and in many cases, residual chemical additives (e.g. scale and corrosion inhibitors) that are added into the hydrocarbon production process.

Feasible alternatives for the management and disposal of produced water should be evaluated and integrated into production design. The main disposal alternatives may include injection into the reservoir to enhance oil recovery, and injection into a dedicated disposal well drilled to a suitable receiving subsurface geological formation. Other possible uses such as irrigation, dust control, or use by other industry, may be appropriate to consider if the chemical nature of the produced water is compatible with these options. Produced water discharges to surface waters or to land should be the last option considered and only if there is no other option available.

Discharged produced water should be treated to meet the limits included in Table 1 in Section 2.1 of this Guideline.[4]

Produced water treatment technologies will depend on the final disposal alternative selected and particular field conditions. Technologies to consider may include combinations of gravity and / or mechanical separation and chemical treatment, and may require a multistage system containing a number of technologies in series to meet injection or discharge requirements. Sufficient treatment system backup capability should be in place to ensure continual operation and or an alternative disposal method should be available.

To reduce the volume of produced water for disposal the following should be considered:

- Adequate well management during well completion activities to minimize water production;
- Recompletion of high water producing wells to minimize water production;
- Use of downhole fluid separation techniques, where possible, and water shutoff techniques, when technically and economically feasible;
- Shutting in high water producing wells.

To minimize environmental hazards related to residual chemical additives in the produced water stream where surface disposal methods are used, production chemicals should be selected carefully by taking into account their volume, toxicity, bioavailability, and bioaccumulation potential.

Disposal into evaporation ponds may be an option for produced waters. The construction and management measures included

[4] Effluent discharge to surface waters should not result in significant impact on human health and environmental receptors. A disposal plan that considers points of discharge, rate of discharge, chemical use and dispersion and environmental risk may be necessary. Discharges should be planned away from environmentally sensitive areas, with specific attention to high water tables, vulnerable aquifers, and wetlands, and community receptors, including water wells, water intakes, and high-value agricultural land.

in this Guideline for surface storage or disposal pits should also apply to produced water ponds.

Hydrostatic Testing Water

Hydrostatic testing of equipment and pipelines involves pressure testing with water to detect leaks and verify equipment and pipeline integrity. Chemical additives (corrosion inhibitors, oxygen scavengers, and dyes) may be added to the water to prevent internal corrosion or to identify leaks. For pipeline testing, test manifolds installed onto sections of newly constructed pipelines, should be located outside of riparian zones and wetlands.

Water sourcing for hydrotesting purposes should not adversely affect the water level or flow rate of a natural water body, and the test water withdrawal rate (or volume) should not exceed 10 percent of the stream flow (or volume) of the water source. Erosion control measures and fish-screening controls should be implemented as necessary during water withdrawals at the intake locations.

The disposal alternatives for test waters following hydrotesting include injection into a disposal well if one is available or discharge to surface waters or land surface. If a disposal well is unavailable and discharge to surface waters or land surface is necessary the following pollution prevention and control measures should be considered:

- Reduce the need for chemicals by minimizing the time that test water remains in the equipment or pipeline;
- If chemical use is necessary, carefully select chemical additives in terms of dose concentration, toxicity, biodegradability, bioavailability, and bioaccumulation potential;
- Conduct toxicity testing as necessary using recognized test methodologies. A holding pond may be necessary to provide time for the toxicity of the water to decrease. Holding ponds should meet the guidance for surface storage or disposal pits as discussed in this Guideline;
- Use the same hydrotest water for multiple tests;
- Hydrostatic test water quality should be monitored before use and discharge and should be treated to meet the discharge limits in Table 1 in Section 2.1 of this Guideline.
- If significant quantities of chemically treated hydrostatic test waters are required to be discharged to a surface water body, water receptors both upstream and downstream of the discharge should be monitored. Post-discharge chemical analysis of receiving water bodies may be necessary to demonstrate that no degradation of environmental quality has occurred;
- If discharged to water, the volume and composition of the test water, as well as the stream flow or volume of the receiving water body, should be considered in selecting an appropriate discharge site to ensure that water quality will not be adversely affected outside of the defined mixing zone;
- Use break tanks or energy dissipators (e.g. protective riprap, sheeting, tarpaulins) for the discharge flow;
- Use sediment control methods (e.g. silt fences, sandbags or hay bales) to protect aquatic biota, water quality, and water users from the potential effect of discharge, such as increased sedimentation and reduced water quality;
- If discharged to land, the discharge site should be selected to prevent flooding, erosion, or lowered agriculture capability of the receiving land. Direct discharge on cultivated land and land immediately upstream of community / public water intakes should be avoided;
- Water discharge during cleaning pig runs and pretest water should be collected in holding tanks and should be discharged only after water-quality testing to ensure that it meets discharge criteria established in Table 1 of Section 2.1 of this Guideline.

Cooling and Heating Systems

Water conservation opportunities provided in the **General EHS Guideline** should be considered for oil and gas facility cooling and heating systems. If cooling water is used, it should be discharged to surface waters in a location that will allow maximum mixing and cooling of the thermal plume to ensure that the temperature is within 3 degrees Celsius of ambient temperature at the edge of the defined mixing zone or within 100 meters of the discharge point, as noted in Table 1 of Section 2.1 of this Guideline.

If biocides and / or other chemical additives are used in the cooling water system, consideration should be given to residual effects at discharge using techniques such as risk based assessment.

Other Waste Waters

Other waste waters routinely generated at onshore oil and gas facilities include sewage waters, drainage waters, tank bottom water, fire water, equipment and vehicle wash waters and general oily water. Pollution prevention and treatment measures that should be considered for these waste waters include:

- *Sewage:* Gray and black water from showers, toilets and kitchen facilities should be treated as described in the **General EHS Guidelines**.

- *Drainage and storm waters:* Separate drainage systems for drainage water from process areas that could be contaminated with oil (closed drains) and drainage water from non-process areas (open drains) should be available to the extent practical. All process areas should be bunded to ensure drainage water flows into the closed drainage system and that uncontrolled contaminated surface run-off is avoided. Drainage tanks and slop tanks should be designed with sufficient capacity for foreseeable operating conditions, and systems to prevent overfilling should be installed. Drip trays, or other controls, should be used to collect run-off from equipment that is not contained within a bunded area and the contents routed to the closed drainage system. Stormwater flow channels and collection ponds installed as part of the open drainage system should be fitted with oil / water separators. Separators may include baffle type or coalescing plate type and should be regularly maintained. Stormwater runoff should be treated through an oil / water separation system able to achieve an oil and grease concentration of 10 mg/L, as noted in Table 1 of Section 2.1 of this Guideline. Additional guidance on the management of stormwater is provided in the **General EHS Guideline.**

- *Tank bottom waters*: The accumulation of tank bottom waters should be minimized by regular maintenance of tank roofs and seals to prevent rainwater infiltration. Consideration should be given to routing these waters to the produced water stream for treatment and disposal, if available. Alternatively they should be treated as a hazardous waste and disposed of in accordance with the facility waste management plan. Tank bottom sludges should also be periodically removed and recycled or disposed of as a hazardous waste.
- *Firewater*: Firewater from test releases should be directed to the facility drainage system.
- *Wash waters*: Equipment and vehicle wash waters should be directed to the closed drainage system.
- *General oily water*: Oily water from drip trays and liquid slugs from process equipment and pipelines should be routed to the closed drainage system.

Surface Storage or Disposal Pits

If surface pits or ponds are used for wastewater storage or for interim disposal during operations, the pits should be constructed outside environmentally sensitive locations.

Wastewater pit construction and management measures should include:

- Installation of a liner so that the bottom and sides of the pit have a coefficient of permeability of no greater than 1 x 10^{-7} centimeters per second (cm/sec). Liners should be compatible with the material to be contained and of sufficient strength and thickness to maintain the integrity of the pit. Typical liners may include synthetic materials, cement / clay type or natural clays, although the hydraulic conductivity of natural liners should be tested to ensure integrity;
- Construction to a depth of typically 5 m above the seasonal high water table;
- Installation of measures (e.g. careful siting, berms) to prevent natural surface drainage from entering the pit or breaching during heavy storms;
- Installation of a perimeter fence around the pit or installation of a screen to prevent access by people, livestock and wildlife (including birds);
- Regular removal and recovery of free hydrocarbons from the pit contents surface;
- Removal of pit contents upon completion of operations and disposal in accordance with the waste management plan;
- Reinstatement of the pit area following completion of operations.

Waste Management

Typical non-hazardous and hazardous wastes[5] routinely generated at onshore facilities other than permitted effluents and emissions include general office and packaging wastes, waste oils, paraffins, waxes, oil contaminated rags, hydraulic fluids, used batteries, empty paint cans, waste chemicals and used chemical containers, used filters, fluorescent tubes, scrap metals, and medical waste, among others.

Waste materials should be segregated into non-hazardous and hazardous wastes for consideration for re-use, recycling, or disposal. Waste management planning should establish a clear strategy for wastes that will be generated including options for waste elimination, reduction or recycling or treatment and disposal, before any wastes are generated. A waste management plan documenting the waste strategy, storage (including facilities and locations) and handling procedures should be developed and should include a clear waste tracking mechanism to track waste consignments from the originating location to the final waste treatment and disposal location. Guidance for waste management of these typical waste streams is provided in the **General EHS Guidelines**.

Significant additional waste streams specific to onshore oil and gas development activities may include:

- Drilling fluids and drilled cuttings
- Produced sand
- Completion and well work-over fluids
- Naturally occurring radioactive materials (NORM)

Drilling Fluids and Drilled Cuttings

The primary functions of drilling fluids used in oil and gas field drilling operations include removal of drilled cuttings (rock chippings) from the wellbore and control of formation pressures. Other important functions include sealing permeable formations, maintaining wellbore stability, cooling and lubricating the drill bit, and transmitting hydraulic energy to the drilling tools and bit. Drilled cuttings removed from the wellbore and spent drilling fluids are typically the largest waste streams generated during oil and gas drilling activities. Numerous drilling fluid systems are available, but they can generally be categorized into one of two fluid systems:

- *Water-Based Drilling Fluids (WBDF)*: The continuous phase and suspending medium for solids (or liquid) is

[5] As defined by local legislation or international conventions.

water or a water miscible fluid. There are many WBDF variations, including gel, salt-polymer, salt-glycol, and salt-silicate fluids;

- *Non-Aqueous Drilling Fluids (NADF)*: The continuous phase and suspending medium for solids (or liquid) is a water immiscible fluid that is oil-based, enhanced mineral oil-based, or synthetic-based.

Diesel-based fluids are also available, but the use of systems that contain diesel as the principal component of the liquid phase is not considered current good practice.

Typically, the solid medium used in most drilling fluids is barite (barium sulfate) for weight, with bentonite clays as a thickener. Drilling fluids also contain a number of chemicals that are added depending on the downhole formation conditions.

Drilling fluids are circulated downhole and routed to a solids control system at the surface facilities where fluids can be separated from the cuttings so that they may be recirculated downhole leaving the cuttings behind for disposal. These cuttings contain a proportion of residual drilling fluid. The volume of cuttings produced will depend on the depth of the well and the diameter of the hole sections drilled. The drilling fluid is replaced when its rheological properties or density of the fluid can no longer be maintained or at the end of the drilling program. These spent fluids are then contained for reuse or disposal (NADFs are typically reused).

Feasible alternatives for the treatment and disposal of drilling fluids and drilled cuttings should be evaluated and included in the planning for the drilling program. Alternative options may include one, or a combination of, the following:

- Injection of the fluid and cuttings mixture into a dedicated disposal well;
- Injection into the annular space of a well;
- Storage in dedicated storage tanks or lined pits prior to treatment, recycling, and / or final treatment and disposal;
- On-site or off-site biological or physical treatment to render the fluid and cuttings non-hazardous prior to final disposal using established methods such as thermal desorption in an internal thermal desorption unit to remove NADF for re-use, bioremediation, landfarming, or solidification with cement and / or concrete. Final disposal routes for the non-hazardous cuttings solid material should be established, and may include use in road construction material, construction fill, or disposal through landfill including landfill cover and capping material where appropriate. In the case of landfarming it should be demonstrated that subsoil chemical, biological, and physical properties are preserved and water resources are protected;
- Recycling of spent fluids back to the vendors for treatment and re-use.

Consider minimizing volumes of drilling fluids and drilled cuttings requiring disposal by:

- Use of high efficiency solids control equipment to reduce the need for fluid change out and minimizing the amount of residual fluid on drilled cuttings;
- Use of slim-hole multilateral wells and coiled tubing drilling techniques, when feasible, to reduce the amount of fluids and cuttings generated.

Pollution prevention and control measures for spent drilling fluids and drilled cuttings should include:

- Minimizing environmental hazards related to residual chemicals additives on discharged cuttings by careful selection of the fluid system.
- Careful selection of fluid additives taking into account technical requirements, chemical additive concentration, toxicity, bioavailability and bioaccumulation potential;

- Monitoring and minimizing the concentration of heavy metal impurities (mainly mercury and cadmium) in barite stock used in the fluid formulation.

The construction and management measures included in this guideline for surface storage or disposal pits should also apply to cuttings and drilling fluid pits. For drilling pits, pit closure should be completed as soon as practical, but no longer than 12 months, after the end of operations. If the drilling waste is to be buried in the pit following operations (the Mix-Bury-Cover disposal method), the following minimum conditions should be met:

- The pit contents should be dried out as far as possible;
- If necessary, the waste should be mixed with an appropriate quantity of subsoil (typically three parts of subsoil to one part of waste by volume);
- A minimum of one meter of clean subsoil should be placed over the mix;
- Topsoil should not be used but it should be placed over the subsoil to fully reinstate the area.
- The pit waste should be analyzed and the maximum lifetime loads should be calculated. A risk based assessment may be necessary to demonstrate that internationally recognized thresholds for chemical exposure are not exceeded.

Produced Sand

Produced sand originating from the reservoir is separated from the formation fluids during hydrocarbon processing. The produced sand can be contaminated with hydrocarbons, but the oil content can vary substantially depending on location, depth, and reservoir characteristics. Well completion should aim to reduce the production of sand at source using effective downhole sand control measures.

Produced sand should be treated as an oily waste, and may be treated and disposed of along with other oil contaminated solid materials (e.g. with cuttings generated when NADFs are used or with tank bottom sludges).

If water is used to remove oil from produced sand, it should be recovered and routed to an appropriate treatment and disposal system (e.g. the produced water treatment system when available).

Completion and Well Work-over Fluids

Completion and well work-over fluids (including intervention and service fluids) can typically include weighted brines, acids, methanol and glycols, and other chemical systems. These fluids are used to clean the wellbore and stimulate the flow of hydrocarbons, or simply used to maintain downhole pressure. Once used these fluids may contain contaminants including solid material, oil, and chemical additives. Chemical systems should be selected with consideration of their volume, toxicity, bioavailability, and bioaccumulation potential. Feasible disposal options should be evaluated for these fluids. Alternative disposal options may include one, or a combination of, the following:

- Collection of the fluids if handled in closed systems and shipping to the original vendors for recycling;
- Injection to a dedicated disposal well, where available;
- Inclusion as part of the produced water waste stream for treatment and disposal. Spent acids should be neutralized before treatment and disposal;
- On-site or off-site biological or physical treatment at an approved facility in accordance with the waste management plan.

Naturally Occurring Radioactive Materials

Depending on the field reservoir characteristics, naturally occurring radioactive material (NORM) may precipitate as scale or sludges in process piping and production vessels. Where

NORM is present, a NORM management program should be developed so that appropriate handling procedures are followed.

If removal of NORM is required for occupational health reasons (section 1.2), disposal options may include: canister disposal during well abandonment; deep well or salt cavern injection; injection into the annular space of a well or disposal to landfill in sealed containers.

Sludge, scale, or NORM-impacted equipment should be treated, processed, or isolated so that potential future human exposures to the treated waste would be within internationally accepted risk-based limits. Recognized industrial practices should be used for disposal. If waste is sent to an external facility for disposal, the facility must be licensed to receive such waste.

Hazardous Materials Management

General guidance for the management of hazardous materials is provided in the **General EHS Guidelines**. The following additional principles should be followed for chemicals used in the onshore oil and gas sector:

- Use chemical hazard assessment and risk management techniques to evaluate chemicals and their effects. Selected chemicals should have been tested for environmental hazards;
- Select chemicals with least hazard and lowest potential environmental and / or health impact, whenever possible;
- Use of Ozone Depleting Substances[6] should be avoided.

Noise

Oil and gas development activities can generate noise during all phases of development including during seismic surveys, construction activities, drilling and production, aerial surveys and air or road transportation. During operations, the main sources of noise and vibration pollution are likely to emanate from flaring and rotating equipment. Noise sources include flares and vents, pumps, compressors, generators, and heaters. Noise prevention and control measures are described in the **General EHS Guidelines**, along with the recommended daytime and night time noise level guidelines for urban or rural communities.

Noise impacts should be estimated by the use of baseline noise assessments for developments close to local human populations. For significant noise sources, such as flare stacks at permanent processing facilities, noise dispersion models should be conducted to establish the noise level guidelines can be met and to assist in the design of facility siting, stack heights, engineered sound barriers, and sound insulation on buildings.

Field related vehicle traffic should be reduced as far as possible and access through local communities should be avoided when not necessary. Flight access routes and low flight altitudes should be selected and scheduled to reduce noise impacts without compromising aircraft and security.

The sound and vibration propagation arising from seismic operations may result in impacts to human populations or to wildlife. In planning seismic surveys, the following should be considered to minimize impacts:

- Minimize seismic activities in the vicinity of local populations wherever possible;
- Minimize simultaneous operations on closely spaced survey lines;
- Use the lowest practicable vibrator power levels;
- Reduce operation times, to the extent practical;
- When shot-hole methods are employed, charge size and hole depth should be appropriately selected to reduce noise levels. Proper back-fill or plugging of holes will also help to reduce noise dispersion;

6 As defined by the Montreal Protocol on Substances That Deplete the Ozone Layer.

- Identify areas and time periods sensitive to wildlife such as feeding and breeding locations and seasons and avoid them when possible;
- If sensitive wildlife species are located in the area, monitor their presence before the onset of noise creating activities, and throughout the seismic program. In areas where significant impacts to sensitive species are anticipated, experienced wildlife observers should be used. Slowly buildup activities in sensitive locations.

Terrestrial Impacts and Project Footprint

Project footprints resulting from exploration and construction activities may include seismic tracks, well pads, temporary facilities, such as workforce base camps, material (pipe) storage yards, workshops, access roads, airstrips and helipads, equipment staging areas, and construction material extraction sites (including borrow pits and quarries).

Operational footprints may include well pads, permanent processing treatment, transmission and storage facilities, pipeline right-of-way corridors, access roads, ancillary facilities, communication facilities (e.g. antennas), and power generation and transmission lines. Impacts may include loss of, or damage to, terrestrial habitat, creation of barriers to wildlife movement, soil erosion, and disturbance to water bodies including possible sedimentation, the establishment of non-native invasive plant species and visual disturbance. The extent of the disturbance will depend on the activity along with the location and characteristics of the existing vegetation, topographic features and waterways.

The visual impact of permanent facilities should be considered in design so that impacts on the existing landscape are minimized. The design should take advantage of the existing topography and vegetation, and should use low profile facilities and storage tanks if technically feasible and if the overall facility footprint is not significantly increased. In addition, consider suitable paint color for large structures that can blend with the background. General guidance on minimizing the project footprint during construction and decommissioning activities is provided in the **General EHS Guidelines**.

Additional prevention and control measures to minimize the footprint of onshore oil and gas developments may include the following:

- Site all facilities in locations that avoid critical terrestrial and aquatic habitat and plan construction activities to avoid sensitive times of the year;
- Minimize land requirements for aboveground permanent facilities;
- Minimize areas to be cleared. Use hand cutting where possible, avoiding the use of heavy equipment such as bulldozers, especially on steep slopes, water and wetland crossings, and forested and ecologically sensitive areas;
- Use a central processing / treatment facility for operations, when practical;
- Minimize well pad size for drilling activities and satellite / cluster, directional, extended reach drilling techniques should be considered, and their use maximized in sensitive locations;
- Avoid construction of facilities in a floodplain, whenever practical, and within a distance of 100 m of the normal high-water mark of a water body or a water well used for drinking or domestic purposes;
- Consider the use of existing utility and transport corridors for access roads and pipeline corridors to the extent possible;
- Consider the routing of access roads to avoid induced impacts such as increased access for poaching;
- Minimize the width of a pipeline right-of-way or access road during construction and operations as far as possible;

- Limit the amount of pipeline trench left open during construction at any one time. Safety fences and other methods to prevent people or animals from falling into open trenches should be constructed in sensitive locations and within 500 m of human populations. In remote areas, install wildlife escape ramps from open trenches (typically every 1 km where wildlife is present);
- Consider use of animal crossing structures such as bridges, culverts, and over crossings, along pipeline and access road rights-of-way;
- Bury pipelines along the entire length to a minimum of 1 m to the top-of-pipe, wherever this is possible;
- Carefully consider all of the feasible options for the construction of pipeline river crossings including horizontal directional drilling;
- Clean-up and fully reinstate following construction activities (including appropriate revegetation using native plant species following construction activities) the pipeline right-of-way and temporary sites such as workforce accommodation camps, storage yards, access roads, helipads and construction workshops, to the pre-existing topography and drainage contours;
- Reinstate off-site aggregate extraction facilities including borrow pits and quarries (opened specifically for construction or extensively used for construction);
- Implement repair and maintenance programs for reinstated sites;
- Consider the implementation of low impact seismic techniques (e.g. minimize seismic line widths (typically no wider than 5 m), limit the line of sight along new cut lines in forested areas (approximately 350 m));
- Consider shot-hole methods in place of vibroseis where preservation of vegetation cover is required and when access is limited. In areas of low cover (e.g. deserts, or tundra with snow cover in place), vibroseis machinery should be selected, but soft soil locations should be carefully assessed to prevent excessive compaction;
- Install temporary and permanent erosion and sediment control measures, slope stabilization measures, and subsidence control and minimization measures at all facilities, as necessary;
- Regularly maintain vegetation growth along access roads and at permanent above ground facilities, and avoid introduction of invasive plant species. In controlling vegetation use biological, mechanical and thermal vegetation control measures and avoid the use of chemical herbicides as much as possible.

If it is demonstrated that the use of herbicides is required to control vegetation growth along access roads or at facilities, then personnel must be trained in their use. Herbicides that should be avoided include those listed under the World Health Organization recommended Classification of Pesticides by Hazard Classes 1a and 1b, the World Health Organization recommended Classification of Pesticides by Hazard Class II (except under conditions as noted in IFC Performance Standard 3: Pollution Prevention and Abatement;[7]), and Annexes A and B of the Stockholm Convention, except under the conditions noted in the convention.[8]

Spills

Spills from onshore facilities, including pipelines, can occur due to leaks, equipment failure, accidents, and human error or as a result of third party interference. Guidelines for release prevention and control planning are provided in the **General EHS Guidelines**, including the requirement to develop a spill prevention and control plan.

[7] IFC Performance Standard 3: Pollution Prevention and Abatement (2006). Available at www.ifc.org/envsocstandards

[8] Stockholm Convention on Persistent Organic Pollutants (2001).

Additional spill prevention and control measures specific to onshore oil and gas facilities include:

- Conduct a spill risk assessment for the facilities and design, drilling, process, and utility systems to reduce the risk of major uncontained spills;
- Ensure adequate corrosion allowance for the lifetime of the facilities or installation of corrosion control and prevention systems in all pipelines, process equipment, and tanks;
- Install secondary containment around vessels and tanks to contain accidental releases;
- Install shutdown valves to allow early shutdown or isolation in the event of a spill;
- Develop automatic shutdown actions through an emergency shutdown system for significant spill scenarios so that the facility may be rapidly brought into a safe condition;
- Install leak detection systems. On pipelines consider measures such as telemetry systems, Supervisory Control and Data Acquisition (SCADA[9]), pressure sensors, shut-in valves, and pump-off systems,
- Develop corrosion maintenance and monitoring programs to ensure the integrity of all field equipment. For pipelines, maintenance programs should include regular pigging to clean the pipeline, and intelligent pigging should be considered as required;
- Ensure adequate personnel training in oil spill prevention, containment, and response;
- Ensure spill response and containment equipment is deployed or available for a response.

All spills should be documented and reported. Following a spill, a root cause investigation should be carried out and corrective actions should be undertaken to prevent reoccurrence. A Spill Response Plan should be prepared, and the capability to implement the plan should be in place. The Spill Response Plan should address potential oil, chemical, and fuel spills from facilities, transport vehicles, loading and unloading operations, and pipeline ruptures. The plan should include:

- A description of the operations, site conditions, logistic support and oil properties;
- Identification of persons responsible for managing spill response efforts, including their authority, roles and contact details;
- Documentation of cooperative measures with government agencies as appropriate;
- Spill risk assessment, defining expected frequency and size of spills from different potential release sources;
- Oil spill trajectory in potentially affected surface water bodies, with oil fate and environmental impact prediction for a number of credible most-probable spill simulations (including a worst case scenario, such as blowout from an oil well) using an adequate and internationally recognized computer model;
- Clear demarcation of spill severity, according to the size of the spill using a clearly defined Tier I, Tier II and Tier III approach;
- Strategies and equipment for managing Tier I spills at a minimum;
- Arrangements and procedures to mobilize external resources for responding to larger spills and strategies for deployment;
- Full list, description, location, and use of on-site and off-site response equipment and the response time estimates for deploying equipment;
- Sensitivity mapping of the environment at risk. Information should include: soil types; groundwater and surface water resources; sensitive ecological and protected areas;

[9] SCADA refers to supervisory control and data acquisition systems, which may be used in oil and gas and other industrial facilities to assist in the monitoring and control of plants and equipment.

agricultural land; residential, industrial, recreational, cultural, and landscape features of significance; seasonal aspects for relevant features, and oil spill response types to be deployed;

- Identification of response priorities, with input from potentially affected or concerned parties;
- Clean up strategies and handling instructions for recovered oil, chemicals, fuels or other recovered contaminated materials, including their transportation, temporary storage, and treatment / disposal.

Decommissioning

Decommissioning of onshore facilities usually includes the complete removal of permanent facilities and well abandonment, including associated equipment, material, and waste disposal or recycling. General guidance on the prevention and control of common environmental impacts during decommissioning activities is provided in the **General EHS Guidelines.** Specific additional requirements to consider for oil and gas facilities include well abandonment and pipeline decommissioning options.

Wells should be abandoned in a stable and safe condition. The hole should be sealed to the ground surface with cement plugs and any known hydrocarbon zones should be isolated to prevent fluid migration. Aquifers should also be isolated. If the land is used for agriculture, the surface casing should be cut and capped below plow depth.

Decommissioning options for pipelines include leaving them in place, or removing them for reuse, recycling or disposal, especially if they are above ground and interfere with human activities. Pipelines left in place should be disconnected and isolated from all potential sources of hydrocarbons; cleaned and purged of hydrocarbons; and sealed at its ends.

A preliminary decommissioning and restoration plan should be developed that identifies disposal options for all equipment and materials, including products used and wastes generated on site. The plan should consider the removal of oil from flowlines, the removal of surface equipment and facilities, well abandonment, pipeline decommissioning and reinstatement. The plan should be further developed during field operations and fully defined in advance of the end of field life, and should include details on the provisions for the implementation of decommissioning activities and arrangements for post decommissioning monitoring and aftercare.

1.2 Occupational Health and Safety

Occupational health and safety issues should be considered as part of a comprehensive hazard or risk assessment, including, for example, a hazard identification study [HAZID], hazard and operability study [HAZOP], or other risk assessment studies. The results should be used for health and safety management planning, in the design of the facility and safe working systems, and in the preparation and communication of safe working procedures.

Facilities should be designed to eliminate or reduce the potential for injury or risk of accident and should take into account prevailing environmental conditions at the site location including the potential for extreme natural hazards such as earthquakes or hurricanes.

Health and safety management planning should demonstrate: that a systematic and structured approach to managing health and safety will be adopted and that controls are in place to reduce risks to as low as reasonably practical; that staff are adequately trained; and that equipment is maintained in a safe condition. The formation of a health and safety committee for the facility is recommended.

A formal Permit to Work (PTW) system should be developed for the facilities. The PTW will ensure that all potentially hazardous work is carried out safely and ensures effective authorization of designated work, effective communication of the work to be carried out including hazards involved, and safe isolation procedures to be followed before commencing work. A lockout / tagout procedure for equipment should be implemented to ensure all equipment is isolated from energy sources before servicing or removal.

The facilities should be equipped, at a minimum, with specialized first aid providers (industrial pre-hospital care personnel) and the means to provide short-term remote patient care. Depending on the number of personnel present and complexity of the facility, provision of an on-site medical unit and medical professional should be considered. In specific cases, telemedicine facilities may be an alternative option.

General facility design and operation measures to manage principal risks to occupational health and safety are provided in the **General EHS Guidelines**. General guidance specific to construction and decommissioning activities is also provided along with guidance on health and safety training, personal protective equipment and the management of physical, chemical, biological and radiological hazards common to all industries.

Occupational health and safety issues for further consideration in onshore oil and gas operations include:

- Fire and explosion
- Air quality
- Hazardous materials
- Transportation
- Well blowouts
- Emergency preparedness and response

Fire and Explosion

General guidance on fire precautions and prevention and control of fire and explosions is provided in the **General EHS Guidelines**.

Onshore oil and gas development facilities should be designed, constructed, and operated according to international standards[10] for the prevention and control of fire and explosion hazards. The most effective way of preventing fires and explosions at oil and gas facilities is by preventing the release of flammable material and gas, and the early detection and interruption of leaks. Potential ignition sources should be kept to a minimum and adequate separation distance between potential ignition sources and flammable materials, and between processing facilities and adjacent buildings[11], should be in place. Facilities should be classified into hazard areas, based on international good practice,[12] and in accordance with the likelihood of release of flammable gases and liquids.

Facility fire and explosion prevention and control measures should also include:

- Provision of passive fire protection to prevent the spread of fire in the event of an incident including:
  - Passive fire protection on load-bearing structures, fire-rated walls, and fire-rated partitions between rooms
  - Design of load-bearing structures taking into account explosion load, or blast-rated walls
  - Design of structures against explosion and the need for blast walls based on an assessment of likely explosion characteristics

[10] An example of good practice includes the United States (US) National Fire Protection Association (NFPA) Code 30: Flammable and Combustible Liquids Code. Further guidance to minimize exposure to static electricity and lightening is American Petroleum Institute (API) Recommended Practice: Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents (2003).
[11] Further information on safe spacing is available in the US NFPA Code 30.
[12] See API RP 500/505 task group on electrical area classification, International Electrotechnical Commission, or British Standards (BS).

  - Specific consideration of blast panel or explosion venting, and fire and explosion protection for wellheads, safe areas, and living areas;
- Prevention of potential ignition sources such as:
  - Proper grounding to avoid static electricity buildup and lightning hazards (including formal procedures for the use and maintenance of grounding connections)[13]
  - Use of intrinsically safe electrical installations and non-sparking tools[14]
- A combination of automatic and manual fire alarm systems that can be heard across the facility;
- Active fire protection systems strategically located to enable rapid and effective response. The fire suppression equipment should meet internationally recognized technical specifications for the type and amount of flammable and combustible materials at the facility.[15] A combination of active fire suppression systems can be used, depending on the type of fire and the fire impact assessment (for example, fixed foam system, fixed fire water system, CO_2 extinguishing system, and portable equipment such as fire extinguishers, and specialized vehicles). The installation of halon-based fire systems is not considered current good practice and should be avoided. Firewater pumps should be available and designed to deliver water at an appropriate rate. Regular checks and maintenance of fire fighting equipment is essential;
- All fire systems should be located in a safe area of the facility, protected from the fire by distance or by fire walls. If the system or piece of equipment is located within a potential fire area, it should be passive fire protected or fail-safe;
- Explosive atmospheres in confined spaces should be avoided by making spaces inert;
- Protection of accommodation areas by distance or by fire walls. The ventilation air intakes should prevent smoke from entering accommodation areas;
- Implementation of safety procedures for loading and unloading of product to transport systems (e.g. ship tankers, rail and tanker trucks, and vessels[16]), including use of fail safe control valves and emergency shutdown equipment;
- Preparation of a fire response plan supported by the necessary resources to implement the plan;
- Provision of fire safety training and response as part of workforce health and safety induction / training, including training in the use fire suppression equipment and evacuation, with advanced fire safety training provided to a designated fire fighting team.

Air Quality

Guidance for the maintenance of air quality in the workplace, along and provision of a fresh air supply with required air quality levels, is provided in the **General EHS Guidelines**.

Facilities should be equipped with a reliable system for gas detection that allows the source of release to be isolated and the inventory of gas that can be released to be reduced. Equipment isolation or the blowdown of pressure equipment should be initiated to reduce system pressure and consequently reduce the release flow rate. Gas detection devices should also be used to authorize entry and operations into enclosed spaces.

Wherever hydrogen sulfide (H_2S) gas may accumulate the following measures should be considered:

- Development of a contingency plan for H_2S release events, including all necessary aspects from evacuation to resumption of normal operations;

[13] See International Safety Guide for Oil Tankers and Terminals (ISGOTT) Chapter 20.
[14] See ISGOTT, Chapter 19.
[15] Such as the US NFPA or equivalent standards.
[16] An example of good industry practice for loading and unloading of tankers includes ISGOTT.

- Installation of monitors set to activate warning signals whenever detected concentrations of H_2S exceed 7 milligrams per cubic meter (mg/m^3). The number and location of monitors should be determined based on an assessment of plant locations prone to H_2S emission and occupational exposure;
- Provision of personal H_2S detectors to workers in locations of high risk of exposure along with self-contained breathing apparatus and emergency oxygen supplies that is conveniently located to enable personnel to safely interrupt tasks and reach a temporary refuge or safe haven;
- Provision of adequate ventilation of occupied buildings to avoid accumulation of hydrogen sulfide gas;
- Workforce training in safety equipment use and response in the event of a leak.

Hazardous Materials

The design of the onshore facilities should reduce exposure of personnel to chemical substances, fuels, and products containing hazardous substances. Use of substances and products classified as very toxic, carcinogenic, allergenic, mutagenic, teratogenic, or strongly corrosive should be identified and substituted by less hazardous alternatives, wherever possible. For each chemical used, a Material Safety Data Sheet (MSDS) should be available and readily accessible on the facility. A general hierarchical approach to the prevention of impacts from chemical hazards is provided in the **General EHS Guidelines**.

A procedure for the control and management of any radioactive sources used during operations should be prepared along with a designated and shielded container for storage when the source is not in use.

In locations where naturally occurring radioactive material (NORM) may precipitate as scale or sludges in process piping and production vessels, facilities and process equipment should be monitored for the presence of NORM at least every five years, or whenever equipment is to be taken out of service for maintenance. Where NORM is detected, a NORM management program should be developed so that appropriate handling procedures are followed. Procedures should determine the classification of the area where NORM is present and the level of supervision and control required. Facilities are considered impacted when surface levels are greater than 4.0 Bq/cm^2 for gamma/beta radiation and 0.4 Bq/cm^2 for alpha radiation.[17] The operator should determine whether to leave the NORM in-situ, or clean and decontaminate by removal for disposal as described in Section 1.1 of this Guideline.

Well Blowouts

A blowout can be caused by the uncontrolled flow of reservoir fluids into the wellbore which may result in an uncontrolled release of hydrocarbons. Blowout prevention measures during drilling should focus on maintaining wellbore hydrostatic pressure by effectively estimating formation fluid pressures and strength of subsurface formations. This can be achieved with techniques such as: proper pre-well planning, drilling fluid logging; using sufficient density drilling fluid or completion fluid to balance the pressures in the wellbore; and installing a Blow Out Preventor (BOP) system that can be rapidly closed in the event of an uncontrolled influx of formation fluids and which allows the well to be circulated to safety by venting the gas at surface and routing oil so that it may be contained. The BOP should be operated hydraulically and triggered automatically, and tested at regular intervals. Facility personnel should conduct well control drills at regular intervals and key personnel should attend a certified well control school periodically.

During production, wellheads should be regularly maintained and monitored, by corrosion control and inspection and pressure

[17] US Environmental Protection Agency (EPA) 49 CFR 173: Surface Contaminated Object (SCO) and International Atomic Energy Agency (IAEA) Safety Standards Series No. ST-1, §508

monitoring. Blow out contingency measures should be included in the facility Emergency Response Plan.

Transportation

Incidents related to land transportation are one of the main causes of injury and fatality in the oil and gas industry. Traffic safety measures for industries are provided in the **General EHS Guidelines**.

Oil and gas projects should develop a road safety management plan for the facility during all phases of operations. Measures should be in place to train all drivers in safe and defensive driving methods and the safe transportation of passengers. Speed limits for all vehicles should be implemented and enforced. Vehicles should be maintained in an appropriate road worthy condition and include all necessary safety equipment.

Specific safety procedures for air transportation (including helicopter) of personnel and equipment should be developed and a safety briefing for passengers should be systematically provided along with safety equipment. Helicopter decks at or near to facilities should follow the requirements of the International Civil Aviation Organization (ICAO).

Emergency Preparedness and Response

Guidance relating to emergency preparedness and response, including emergency resources, is provided in the **General EHS Guidelines**. Onshore oil and gas facilities should establish and maintain a high level of emergency preparedness to ensure incidents are responded to effectively and without delay. Potential worst case accidents should be identified by risk assessment and appropriate preparedness requirements should be designed and implemented. An emergency response team should be established for the facility that is trained to respond to potential emergencies, rescue injured persons, and perform emergency actions. The team should coordinate actions with other agencies and organizations that may be involved in emergency response.

Personnel should be provided with adequate and sufficient equipment that is located appropriately for the evacuation of the facility and should be provided with escape routes to enable rapid evacuation to a safe refuge. Escape routes should be clearly marked and alternative routes should be available. Exercises in emergency preparedness should be practiced at a frequency commensurate with the project risk. At a minimum, the following practice schedule should be implemented:

- Quarterly drills without equipment deployment;
- Evacuation drills and training for egress from the facilities under different weather conditions and time of day;
- Annual mock drills with deployment of equipment;
- Updating training, as needed, based on continuous evaluation.

An Emergency Response Plan should be prepared that contains the following measures, at a minimum:

- A description of the response organization (structure, roles, responsibilities, and decision makers);
- Description of response procedures (details of response equipment and location, procedures, training requirements, duties, etc.);
- Descriptions and procedures for alarm and communications systems;
- Precautionary measures for securing the wells;
- Relief well arrangements, including description of equipment, consumables, and support systems to be utilized;
- Description of on-site first aid supplies and available backup medical support;
- Description of other emergency facilities such as emergency fueling sites;

- Description of survival equipment and gear, alternate accommodation facilities, and emergency power sources;
- Evacuation procedures;
- Emergency Medical Evacuation (MEDIVAC) procedures for injured or ill personnel;
- Policies defining measures for limiting or stopping events, and conditions for termination of action.

1.3 Community Health and Safety

Community health and safety impacts during the construction and decommissioning of facilities are common to those of most other industrial facilities and are discussed in the **General EHS Guidelines**.

Physical Hazards

Community health and safety issues specific to oil and gas facilities may include potential exposure to spills, fires, and explosions. To protect nearby communities and related facilities from these hazards, the location of the project facilities and an adequate safety zone around the facilities should be established based on a risk assessment. A community emergency preparedness and response plan that considers the role of communities and community infrastructure as appropriate should also be developed. Additional information on the elements of emergency plans is provided in the **General EHS Guidelines.**

Communities may be exposed to physical hazards associated with the facilities including wells and pipeline networks. Hazards may result from contact with hot components, equipment failure, the presence of operational pipelines or active and abandoned wells and abandoned infrastructure which may generate confined space or falling hazards. To prevent public contact with dangerous locations and equipment and hazardous materials, access deterrents such as fences and warning signs should be installed around permanent facilities and temporary structures. Public training to warn of existing hazards, along with clear guidance on access and land use limitations in safety zones or pipeline rights of way should be provided.

Community risk management strategies associated with the transport of hazardous materials by road is presented in the **General EHS Guidelines** (refer specifically to the sections on "Hazardous Materials Management" and "Traffic Safety"). Guidance applicable to transport by rail is provided **EHS Guidelines for Railways** while transport by sea is covered in the **EHS Guidelines for Shipping.**

Hydrogen Sulfide

The potential for exposure of members of the community to facility air emissions should be carefully considered during the facility design and operations planning process. All necessary precautions in the facility design, facility siting and / or working systems and procedures should be implemented to ensure no health impacts to human populations and the workforce will result from activities.

When there is a risk of community exposure to hydrogen sulfide from activities, the following measures should be implemented:

- Installation of a hydrogen sulfide gas monitoring network with the number and location of monitoring stations determined through air dispersion modeling, taking into account the location of emissions sources and areas of community use and habitation;
- Continuous operation of the hydrogen sulfide gas monitoring systems to facilitate early detection and warning;
- Emergency planning involving community input to allow for effective response to monitoring system warnings.

Security

Unauthorized access to facilities should be avoided by perimeter fencing surrounding the facility and controlled access points (guarded gates). Public access control should be applied. Adequate signs and closed areas should establish the areas where security controls begin at the property boundaries. Vehicular traffic signs should clearly designate the separate entrances for trucks / deliveries and visitor / employee vehicles. Means for detecting intrusion (for example, closed-circuit television) should be considered. To maximize opportunities for surveillance and minimize possibilities for trespassers, the facility should have adequate lighting.2.0

2.0 Performance Indicators and Monitoring

2.1 Environment

Emissions and Effluent Guidelines

Table 1 presents effluent and waste guidelines for onshore oil and gas development. When one or more members of the World Bank Group are involved in a project, these EHS Guidelines are applied as required by their respective policies and standards. The guidelines are assumed to be achievable under normal operating conditions in appropriately designed and operated facilities through the application of pollution prevention and control techniques discussed in the preceding sections of this document.

Effluent guidelines are applicable for direct discharges of treated effluents to surface waters for general use. Site-specific discharge levels may be established based on the availability and conditions in use of publicly operated sewage collection and treatment systems or, if discharged directly to surface waters, on the receiving water use classification as described in the **General EHS Guidelines**.

Combustion source emissions guidelines associated with steam- and power-generation activities from sources with a capacity equal to or lower than 50 MWth are addressed in the **General EHS Guidelines** with larger power source emissions addressed in the **Thermal Power EHS Guidelines**. Guidance on ambient considerations based on the total load of emissions is provided in the **General EHS Guidelines**.

Environmental Monitoring

Environmental monitoring programs for this sector should be implemented to address all activities that have been identified to have potentially significant impacts on the environment, during normal operations and upset conditions. Environmental monitoring activities should be based on direct or indirect indicators of emissions, effluents, and resource use applicable to the particular project.

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Monitoring frequency should be sufficient to provide representative data for the parameter being monitored. Monitoring should be conducted by trained individuals following monitoring and record-keeping procedures and using properly calibrated and maintained equipment. Monitoring data should be analyzed and reviewed at regular intervals and compared with the operating standards so that any necessary corrective actions can be taken. Additional guidance on applicable sampling and analytical methods for emissions and effluents is provided in the **General EHS Guidelines**.

Table 1. Emissions, Effluent and Waste Levels from Onshore Oil and Gas Development	
Parameter	**Guideline Value**
Drilling fluids and cuttings	Treatment and disposal as per guidance in Section 1.1 of this document.
Produced sand	Treatment and disposal as per guidance in Section 1.1 of this document.
Produced water	Treatment and disposal as per guidance in Section 1.1 of this document. For discharge to surface waters or to land: o Total hydrocarbon content: 10 mg/L o pH: 6 - 9 o BOD: 25 mg/L o COD: 125 mg/L o TSS: 35 mg/L o Phenols: 0.5 mg/L o Sulfides: 1 mg/L o Heavy metals (total)[a]: 5 mg/L o Chlorides: 600 mg/l (average), 1200 mg/L (maximum)
Hydrotest water	Treatment and disposal as per guidance in section 1.1 of this document. For discharge to surface waters or to land, see parameters for produced water in this table.
Completion and well work-over fluids	Treatment and disposal as per guidance in Section 1.1 of this document. For discharge to surface waters or to land: : o Total hydrocarbon content: 10 mg/L. o pH: 6 – 9
Stormwater drainage	Stormwater runoff should be treated through an oil/water separation system able to achieve oil & grease concentration of 10 mg/L.
Cooling water	The effluent should result in a temperature increase of no more than 3° C at edge of the zone where initial mixing and dilution take place. Where the zone is not defined, use 100 m from point of discharge.
Sewage	Treatment as per guidance in the General EHS Guidelines, including discharge requirements.
Air Emissions	Treatment as per guidance in Section 1.1 of this document. Emission concentrations as per General EHS Guidelines, and: o H_2S: 5 mg/Nm^3
Notes: [a] Heavy metals include: Arsenic, cadmium, chromium, copper, lead, mercury, nickel, silver, vanadium, and zinc.	

2.2 Occupational Health and Safety

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Occupational Health and Safety Guidelines

Occupational health and safety performance should be evaluated against internationally published exposure guidelines, of which examples include the Threshold Limit Value (TLV®) occupational exposure guidelines and Biological Exposure Indices (BEIs®) published by American Conference of Governmental Industrial Hygienists (ACGIH),[18] the Pocket Guide to Chemical Hazards published by the United States National Institute for Occupational Health and Safety (NIOSH),[19] Permissible Exposure Limits (PELs) published by the Occupational Safety and Health Administration of the United States (OSHA),[20] Indicative Occupational Exposure Limit Values published by European Union member states,[21] or other similar sources.

Particular attention should be given to the occupational exposure guidelines for hydrogen sulfide (H_2S). For guidelines on occupational exposure to Naturally Occurring Radioactive Material (NORM), readers should consult the average and maximum values published by the Canadian NORM Waste Management Committee, Health Canada, and the Australian Petroleum Production and Exploration Association or other internationally recognized sources.

Accident and Fatality Rates

Projects should try to reduce the number of accidents among project workers (whether directly employed or subcontracted) to a rate of zero, especially accidents that could result in lost work time, different levels of disability, or even fatalities. Facility rates may be benchmarked against the performance of facilities in this sector in developed countries through consultation with published sources (e.g. US Bureau of Labor Statistics and UK Health and Safety Executive)[22].

Occupational Health and Safety Monitoring

The working environment should be monitored for occupational hazards relevant to the specific project. Monitoring should be designed and implemented by accredited professionals[23] as part of an occupational health and safety monitoring program. Facilities should also maintain a record of occupational accidents and diseases and dangerous occurrences and accidents. Additional guidance on occupational health and safety monitoring programs is provided in the **General EHS Guidelines**.

[18] Available at: http://www.acgih.org/TLV/ and http://www.acgih.org/store/
[19] Available at: http://www.cdc.gov/niosh/npg/
[20] Available at: http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=9992
[21] Available at: http://europe.osha.eu.int/good_practice/risks/ds/oel/
[22] Available at: http://www.bls.gov/iif/ and http://www.hse.gov.uk/statistics/index.htm
[23] Accredited professionals may include Certified Industrial Hygienists, Registered Occupational Hygienists, or Certified Safety Professionals or their equivalent.

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Annex A: General Description of Industry Activities

The primary products of the oil and gas industry are crude oil, natural gas liquids, and natural gas. Crude oil consists of a mixture of hydrocarbons having varying molecular weights and properties. Natural gas can be produced from oil wells, or wells can be drilled with natural gas as the primary objective. Methane is the predominant component of natural gas, but ethane, propane, and butane are also significant components. The heavier components, including propane and butane, exist as liquids when cooled and compressed and these are often separated and processed as natural gas liquids.

Exploration Activities

Seismic Surveys

Seismic surveys are conducted to pinpoint potential hydrocarbon reserves in geological formations. Seismic technology uses the reflection of sound waves to identify subsurface geological structures. The surveys are conducted through the generation of seismic waves by a variety of sources ranging from explosives that are detonated in shot-holes drilled below the surface, to vibroseis machinery (a vibrating pad lowered to the ground from a vibroseis truck). Reflected seismic waves are measured with a series of sensors known as geophones laid out in series on the surface.

Exploration Drilling

Exploratory drilling activities onshore follow the analysis of seismic data to verify and quantify the amount and extent of oil and gas resources from potentially productive geological formations. A well pad is constructed at the chosen location to accommodate a drilling rig, associated equipment and support services. The drilling rig and support services are transported to site, typically in modules and assembled.

Once on location, a series of well sections of decreasing diameter are drilled from the rig. A drill bit, attached to the drill string suspended from the rig's derrick, is rotated in the well. Drill collars are attached to add weight and drilling fluids are circulated through the drill string and pumped through the drill bit. The fluid has a number of functions. It imparts hydraulic force that assists the drill bit cutting action, and it cools the bit, removes cuttings rock from the wellbore and protects the well against formation pressures. When each well section has been drilled, steel casing is run into the hole and cemented into place to prevent well collapse. When the reservoir is reached the well may be completed and tested by running a production liner and equipment to flow the hydrocarbons to the surface to establish reservoir properties in a test separator.

Field Development and Production

Development and production is the phase during which the infrastructure is installed to extract the hydrocarbon resource over the life of the estimated reserve. It may involve the drilling of additional wells, the operation of central production facilities to treat the produced hydrocarbons, the installation of flowlines, and the installation of pipelines to transport hydrocarbons to export facilities.

Following development drilling and well completion, a "Christmas tree" is placed on each wellhead to control flow of the formation fluids to the surface. Hydrocarbons may flow freely from the wells if the underground formation pressures are adequate, but additional pressure may be required such as a sub-surface pump or the injection of gas or water through dedicated injection wells to maintain reservoir pressure. Depending on reservoir conditions, various substances (steam, nitrogen, carbon dioxide, and surfactants) may be injected into the reservoir to remove more oil from the pore spaces, increase production, and extend well life.

Most wells produce in a predictable pattern called a decline curve where production increases relatively rapidly to a peak, and then follows a long, slow decline. Operators may periodically perform well workovers to clean out the wellbore, allowing oil or gas to move more easily to the surface. Other measures to increase production include fracturing and treating the bottom of the wellbore with acid to create better pathways for the oil and gas to move to the surface. Formation fluids are then separated into oil, gas and water at a central production facility, designed and constructed depending on the reservoir size and location.

Crude oil processing essentially involves the removal of gas and water before export. Gas processing involves the removal of liquids and other impurities such as carbon dioxide, nitrogen and hydrogen sulfide. Oil and gas terminal facilities receive hydrocarbons from outside locations sometimes offshore and process and store the hydrocarbons before they are exported. There are several types of hydrocarbon terminals, including inland pipeline terminals, onshore / coastal marine receiving terminals (from offshore production), barge shipping, or receiving terminals.

Produced oil and gas may be exported by pipeline, trucks, or rail tank cars. Gas-to-liquids is an area of technology development that allows natural gas to be converted to a liquid. Gas is often exported as liquefied natural gas (LNG). Pipelines are constructed in a sequential process, including staking of the right-of-way (ROW) and pipeline centerline; ROW clearing and grading; trenching (for buried pipeline); pipe laying, welding, and bending; field coating of welded joints; testing; lowering; trench backfilling; and ROW reinstatement . Pumps or compressors are used to transport liquids or gas from the oil and gas fields to downstream or export facilities. During commissioning, flowlines, pipelines, and associated facilities (e.g. block valves and meters, regulators and relief devices, pump stations, pigging stations, storage tanks) are filled with water and hydrotested to ensure integrity. Pipeline operation usually requires frequent inspections (ground and aerial surveillance, and facility inspections) and periodic ROW and facility maintenance. Production and pipeline operation is usually monitored and controlled from a central location through a supervisory control and data acquisition system (SCADA) which allows field operating variables to be monitored such as flow rate, pressure, and temperature and to open and close valves.

Decommissioning and Abandonment

The decommissioning of onshore facilities occurs when the reservoir is depleted or the production of hydrocarbons from that reservoir becomes unprofitable. Parts of the onshore facilities, such as the aboveground facilities located in the oil or gas field area and along the transmission lines, are treated to remove hydrocarbons and other chemicals and wastes or contaminants and removed. Other components, such as flowlines and pipelines, are often left in place to avoid environmental disturbances associated with removal. Wells are plugged and abandoned to prevent fluid migration within the wellbore or to the surface. The downhole equipment is removed and the perforated parts of the wellbore are cleaned of soil, scale, and other debris. The wellbore is then plugged. Fluids with an appropriate density are placed between the plugs to maintain adequate pressure. During this process, the plugs are tested to verify their correct placement and integrity. Finally, the casing is cut off below the surface and capped with a cement plug.

APPENDIX D – Glossary of Terms

Amelioration – The ability to reduce the visual impact of a development through siting, design, colour or screening.

Sensitivity – The degree to which various user groups will respond to change based on their expectation of a particular experience in a given setting, i.e. the expectation of a high level of visual amenity in a national park.

Modification Level – The degree to which a development contrasts or blends with its setting.

Visual Impact – The result of assessing the sensitivity level of a viewer and the modification level of a development.

Viewshed – The area visible from a particular viewing location.

Zone of Visual Influence (ZVI) – The area over which an object can be seen within the landscape

Visual Amenity – The qualities of a landscape setting that are appreciated and valued by a viewer.

Viewer Perception – The way in which people respond to what they are seeing as influenced by things other than purely visual, – i.e. noise and economic benefits.

APPENDIX E – References

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APPENDIX F – Site Component Areas

GIS AREA AND DISTANCE CALCULATIONS FOR 1284_PNG_LNG

LNG FACILITY	(Data obtained from Downstream_LNG_Facility_Design layer)				
	Area name	**Layer**	**Perimeter (km)**	**Area (km²)**	**Area (Hectares)**
	Flare Area	PROCESS UNIT	0.600	0.02	2.25
	Flare Area (50m radius)	PROCESS UNIT	0.314	0.01	0.78
	Flare Area (550m radius)	PROCESS UNIT	3.456	0.95	95.01
	45 db Limit (1571m radius)	JETTY	9.870	7.75	775.15
	Fence	FENCE	12.509	7.03	702.88
	Process Unit (2 trains)	PROCESS UNIT	2.638	0.40	40.08
	Support Buildings	PROCESS UNIT	1.639	0.17	16.77
	Future Process Unit (2 trains)	PROCESS UNIT	2.638	0.40	40.08
	Southern Pipeline Approach	PIPELINE	0.195	0.00	0.30
	Permanent Living and Support Facilities	PROCESS UNIT	1.800	0.20	20.00
	Bog Comp (Cond. Storage and LNG TK1)	PROCESS UNIT	2.942	0.46	46.37
	Tankage	TANKAGE	5.905	2.63	262.98
	Helipad	PROCESS UNIT	0.400	0.01	1.00
	Temporary Construction Camp	PROCESS UNIT	4.173	0.74	73.81
	Jetty Buffer	JETTY	5.364	1.84	183.86
	Southern Pipeline Approach Fence	FENCE	0.632	0.02	2.43
	LNG TK1		2.264	0.31	30.85
	Cond. Storage		1.589	0.15	15.45

OTHER				
	Distances	**Notes**	**Distance (km)**	
	Distance from Port Moresby	Straight line distance to perimeter fence (Downstream_LNG_Facility_Design layer)	20.000	
	Distance from pilot station to jetty	Straight line distance from pilot station to western edge of jetty	11.895	
	Distance from Motekea to jetty	By sea (inner tug boat route, calculated from TugBoat_Routes layer)	33.626	
	Road between Curtin Bros and SP152	Lealea Road (Digitized from PNG_2000_Census_Road & ExxonMobil_PNG_10242-c_WGS84_UTM55S.ecw layers, from boundary of SP152 to road intersection at Motukea Plant)	9.664	
	Road diversion distance	(Calculated from Downstream_LNG_Facility_Design layer)	8.288	
	Distance from plant to Papa	(Straight line distance)	4.001	
	Distance from plant to Boera	(Straight line distance)	5.819	
	Coast between Papa and Boera	(Digitized from ADC_Coastline_layer)	11.743	
	Jetty length	Distance from MOF to LNG Loading (Calculated with measure tool from Downstream_LNG_Facility_Design)	0.75	
	Causeway length	Distance from LNG TK1 to MOF (Calculated with measure tool from Downstream_LNG_Facility_Design)	1.85	
	Total Jetty/Causeway length	Distance from LNG TK1 to LNG Loading (Calculated with measure tool from Downstream_LNG_Facility_Design)	2.60	
	Areas		**Area (km²)**	**Area (Hectares)**
	Total area within LNG site	Area within Perimeter fence (Downstream_LNG_Facility_Design layer)	7.03	702.88
	Total area of permanent exclusion zone	Comprised of Jetty Buffer & Perimeter Fence from the Downstream_LNG_Facility_Design layer (Digitized from Downstream_LNG_Facility_Design layer)	8.87	886.74
	Total area of Caution Bay	(Calculated from Caution_Bay_Extent & ADC_Coastline layers	434.83	43483.08
	Total lease area	(Calculated from new Downstream_LNG_Facility_Design layer)	23.88	2387.55